# DUKE ENERGY PROGRESS
# INTEGRATED RESOURCE PLAN

## 2020 MODIFIED




## DUKE ENERGY PROGRESS 2020 MODIFIED INTEGRATED RESOURCE PLAN CONTENTS



# 1 EXECUTIVE SUMMARY

## INTRODUCTION AND BACKGROUND

In response to Order No. 2021-447 of the Public Service Commission of South Carolina (Commission), Duke Energy Progress, LLC (DEP or the Company) presents the following modified integrated resource planning portfolios and analysis (SC Supplemental Portfolios and Analysis). These portfolios illustrate resource selections based on modified assumptions, as directed by the Commission, and are intended to supplement the Integrated Resource Plan submitted by DEP to the Commission on September 1, 2020 (September 2020 IRP). The SC Supplemental Portfolios and Analysis, together with the portfolios and analysis presented in the September 2020 IRP, represent DEP's 2020 SC Modified IRP.

## SEPTEMBER 2020 IRP

The September 2020 IRP presented a comprehensive plan that balances resource adequacy and capacity to serve anticipated peak electrical load, consumer affordability and least cost, as well as compliance with applicable state and federal environmental regulations. As a regulated utility with the obligation to reliably serve customers, the September 2020 IRP considered operational, technological, and economic risks associated with the different portfolios. The September 2020 IRP provided significant detail surrounding six resource portfolios that match forecasted electricity requirements, with demand-side programs as well as supply-side resources, with an appropriate reserve margin, to maintain system reliability for customers over the next 15 years, while achieving carbon reductions consistent with Duke Energy's climate goals.

The September 2020 IRP was comprised of two base case portfolios and four alternative portfolios:

- **Portfolio A:** Base Without Carbon Policy

- **Portfolio B:** Base With Carbon Policy
- **Portfolio C:** Earliest Practicable Coal Retirements
- **Portfolio D:** 70% CO2 Reduction: Offshore Wind
- **Portfolio E:** 70% CO2 Reduction: Nuclear SMR
- **Portfolio F:** No New Gas Generation

The September 2020 IRP reflected two economically optimized base cases: each developed with a different assumption on a future carbon emissions policy. Portfolio A was economically optimized assuming no carbon policy, which is the current state of law and regulation applicable to the Company today. Portfolio B was economically optimized assuming a form of carbon policy is enacted in the future.

The other four portfolios were developed to achieve specific technology and emissions reduction outcomes of interest to stakeholders and policy makers and showed different trajectories for carbon reduction with varying inputs such as coal retirement dates, types of resources and the level and pace of technology adoption rates, as well as contributions from energy efficiency and demand-side management initiatives. The collection of portfolios presented in the September 2020 IRP represents a comprehensive plan and provides the Company flexibility to adapt to changing standards, technology, and policy changes in the future.

## ORDER NO. 2021-447

On June 28, 2021, the Commission issued Order No. 2021-447, which instructed DEP, in part, to modify certain modeling assumptions and file the results of the additional modeling and analysis with the Commission within 60 days. DEP has conducted the additional analysis required by the Commission, which is demonstrated in the SC Supplemental Portfolios, as described herein.

- **Ordering Paragraph 1:** As described in Section 3, additional load forecast scenarios have been incorporated into the modified IRP analysis which captures long-term economic and other types of uncertainty.

- **Ordering Paragraphs 2 - 9:** Applicable to future resource planning.

- **Ordering Paragraph 10:** Modifications to natural gas pricing forecasts are incorporated into Portfolios A2, B2, and C2 as described in Section 3.

- **Ordering Paragraphs 11 - 12: $**38/MWh solar PPA is included as a selectable resource in all new portfolios in the SC Supplemental Portfolios, as described in Sections 2 and 3.
- **Ordering Paragraph 13:** $36/MWh solar PPA and $40/MWh PPA options are included as sensitivities, as described in Section 3.
- **Ordering Paragraph 14:** All SC Supplemental Portfolios include the extension of the solar investment tax credit, as described in Section 2 and 3.
- **Ordering Paragraph 15:** All SC Supplemental Portfolios model incremental future solar additions as single-axis tracking, as described in Section 2 and 3.
- **Ordering Paragraph 16:** The NREL ATB "Low" battery storage cost forecast is incorporated into Portfolios A2, B2, and C2 as described in in Section 2 and 3.
- **Ordering Paragraph 17:** The 500 MW interconnection limit included in Portfolios A, B, and C have been expanded to 750 MW in SC Supplemental Portfolios A1, A2, B1, B2, C1, and C2, as described in Section 2.
- **Ordering Paragraph 18:** Applicable to future resource planning.
- **Ordering Paragraph 19:** Minimax regret analysis of the type described by ORS Witness Kollen has been incorporated into the Company's portfolio analysis, risk assessment, and portfolio selection process, and discussed in more detail in Section 3.
- **Ordering Paragraphs 20-22:** Applicable to future resource planning.

## SC SUPPLEMENTAL PORTFOLIOS

The SC Supplemental Portfolios are comprised of nine portfolios that are developed with modeling assumptions similar to the corresponding original six portfolios provided in the September 2020 IRP, except as modified in response to the Commission's Order.

Modeling inputs and assumptions used to develop the September 2020 IRP were based on technology costs and market conditions at the time the analysis was conducted. While the Company's SC Supplemental Portfolios incorporate the changes to inputs and assumptions required by the Commission's Order, the SC Supplemental Portfolios do not represent an IRP update and the Company has not comprehensively updated all modeling inputs and assumptions for purposes of this modified 2020 IRP. Therefore, the other inputs and assumptions used to develop the SC Supplemental Portfolios are consistent with the September 2020 IRP. Given the limited nature of the ordered changes to the inputs in the SC Supplemental Portfolios, it is important to view the results and analysis herein as reflecting a "snapshot in time," recognizing that conditions have since changed with respect to technology costs, market conditions, and policy changes under consideration. Future updates to technology costs and market conditions will naturally result in some changes to the resource mixes, and the Company looks forward to engaging stakeholders in the development of the comprehensive 2022 IRPs where fulsome updates to these inputs and assumptions will be incorporated.

The SC Supplemental Portfolios are described briefly below and in greater detail in Section 3.

Each of DEP's nine supplemental portfolios is a modification of a corresponding portfolio from the September 2020 IRP. For example, Portfolios A1 and A2 were developed in the same manner as Portfolio A, with certain adjustments to inputs, as shown in Table 1. Consistent with Portfolios A and B from the September 2020 IRP, the new Portfolios A1, A2, B1, and B2 are economically optimized, meaning the resource selections adhere to traditional "least cost" planning criteria based on the assumptions used to develop the portfolios.

Consistent with Portfolios C, D, E, and F from the September 2020 IRP, the new Portfolios C1, C2, D1, E1, and F1 are "outcome oriented," in that they are designed to achieve certain carbon reductions or focus on specific technology mixes. As a result, the resource selections are not driven entirely by economics, but rather to achieve targeted resource planning outcomes. Consistent with Portfolio C, Portfolios C1 and C2 seek to retire coal as quickly as possible. Consistent with Portfolios D and E, Portfolios D1 and E1 seek to achieve carbon reductions through emerging technologies (offshore wind and small modular nuclear reactors respectively). Portfolio F1 examines the potential of not building any new natural gas generators, in a manner similar to Portfolio F.

All new portfolios ending in (1) incorporate the following changes in assumptions, as shown in Table 1:

a. Expanding interconnection limits to 750 MW per year for solar technologies;
b. Including the federal solar investment tax credit expansion;
c. Modeling all future solar additions as single-axis tracking; and

d. Including a $38/MWh solar power purchase agreement (PPA) option as a selectable resource.

All new portfolios ending in (2) incorporate the following changes in assumptions, as shown in Table 1:

a. All changes described in (a) – (d) above;
b. Revised natural gas price forecast methodology to reflect 18 months of market price before transitioning over an 18-month period to a fundamental forecast; and
c. Alternate battery storage cost assumptions to reflect the NREL ATB Low forecast.

**Table 1-A** shows the inputs and assumptions used in the initial DEP September 2020 IRP Portfolios A-F and the SC Supplemental Portfolios.

## TABLE 1-A
## SC SUPPLEMENTAL PORTFOLIOS KEY INPUT AND ASSUMPTIONS

| PORTFOLIO OUTCOME | IRP FILING | IRP PATHWAY | CARBON POLICY | FEDERAL SOLAR INVESTMENT TAX CREDIT EXTENSION | ANNUAL SOLAR INTERCONNECTION LIMITS [MW] | PERCENT OF FUTURE SOLAR AS SINGLE AXIS TRACKING | $38/MWH SOLAR PPA AS SELECTABLE RESOURCE | NATURAL GAS PRICE FORECAST | BATTERY COST FORECAST |
|---|---|---|---|---|---|---|---|---|---|
| Base Case without Carbon Policy | Original | A | No Carbon Policy | No Extension | 500 | 60% | Excluded | 10 Years Market + Fundamental Forecast | Carolinas Specific Forecast |
| | Modified | A1 | No Carbon Policy | Extension | 750 | 100% | Included | 10 Years Market + Fundamental Forecast | Carolinas Specific Forecast |
| | Modified | A2 | No Carbon Policy | Extension | 750 | 100% | Included | 18 Months Market + Fundamental Forecast | 2020 NREL ATB Low Forecast |
| Base Case with Carbon Policy | Original | B | With Carbon Policy | N Extension | 500 | 60% | Excluded | 10 Years Market + Fundamental Forecast | Carolinas Specific Forecast |
| | Modified | B1 | With Carbon Policy | Extension | 750 | 100% | Included | 10 Years Market + Fundamental Forecast | Carolinas Specific Forecast |
| | Modified | B2 | With Carbon Policy | Extension | 750 | 100% | Included | 18 Months Market + Fundamental Forecast | 2020 NREL ATB Low Forecast |
| Earliest Practicable Coal Retirements | Original | C | With Carbon Policy | No Extension | 500 | 60% | Excluded | 10 Years Market + Fundamental Forecast | Carolinas Specific Forecast |
| | Modified | C1 | With Carbon Policy | Extension | 750 | 100% | Included | 10 Years Market + Fundamental Forecast | Carolinas Specific Forecast |
| | Modified | C2 | With Carbon Policy | Extension | 750 | 100% | Included | 18 Months Market + Fundamental Forecast | 2020 NREL ATB Low Forecast |
| 70% $CO_2$ Reduction: Offshore Wind | Original | D | With Carbon Policy | No Extension | 900 | 60% | Excluded | 10 Years Market + Fundamental Forecast | Carolinas Specific Forecast |
| | Modified | D1 | With Carbon Policy | Extension | 900 | 100% | Included | 10 Years Market + Fundamental Forecast | Carolinas Specific Forecast |
| 70% $CO_2$ Reduction: Nuclear SMR | Original | E | With Carbon Policy | No Extension | 900 | 60% | Excluded | 10 Years Market + Fundamental Forecast | Carolinas Specific Forecast |
| | Modified | E1 | With Carbon Policy | Extension | 900 | 100% | Included | 10 Years Market + Fundamental Forecast | Carolinas Specific Forecast |
| No New Gas Generation | Original | F | With Carbon Policy | No Extension | 900 | 60% | Excluded | 10 Years Market + Fundamental Forecast | Carolinas Specific Forecast |
| | Modified | F1 | With Carbon Policy | Extension | 900 | 100% | Included | 10 Years Market + Fundamental Forecast | Carolinas Specific Forecast |

## SENSITIVITY AND SCENARIO ANALYSIS

Similar to the September 2020 IRP, DEP conducted sensitivity analysis to demonstrate the isolated impact of singular input assumption adjustments on resource selection and costs compared to the economically optimized supplemental IRP portfolios. For this analysis, DEP evaluated portfolio sensitivity to inputs such as high/low load forecast, high/low natural gas forecast, high/low solar interconnection limits, high/low solar cost, high/low energy efficiency, and high/low demand response.

Also similar to the September 2020 IRP, DEP conducted robust scenario analysis to the SC Supplemental Portfolios. The scenario analysis quantifies how each of the supplemental portfolios performs with respect to cost, reliability, and environmental considerations across a range of natural gas price and carbon price forecasts. The results of this modeling and analysis assist in determining a portfolio's ability to perform robustly across a range of possible futures. While this is an important factor in considering a preferred portfolio, it is just one of several the Company used in selecting a portfolio as most reasonable and prudent. The results of the scenario analysis and sensitivity analysis are provided in Section 3.

## MODELING RESULTS

Results of the nine SC Supplemental Portfolios are summarized in Table 1-B (showing DEP results) and 1-C (showing combined results of DEP and Duke Energy Carolina, LLC (DEC) results) below and greater detail is provided in Section 3.

Overall, the SC Supplemental Portfolios show the diversity of potential future resource mixes based on specific assumptions and drivers for each portfolio. Significant commitments to energy efficiency and demand-side management programs along with additions of solar, wind, and storage are present in all portfolios and are critical to reduce future carbon emissions. Natural gas continues to be a necessary flexible and dispatchable resource to ensure continued power supply reliability and to respond to variable energy resources as the various portfolios transition to higher penetrations of non-dispatchable, carbon-free generation. New natural gas generators shown in these portfolios will be capable of utilizing a minimum of 30% hydrogen, with later additions potentially reaching 100% hydrogen capability by 2030.

# TABLE 1-B

## DEP SC SUPPLEMENTAL PORTFOLIOS MODELING RESULTS

| | Duke Energy Progress | | | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| **Pathway** | A1 | | A2 | | B1 | | B2 | | C1 | | C2 | | D1 | | E1 | | F1 | |
| **System $CO_2$ Reduction (2030 \| 2035)[1]** | 56% | 55% | 57% | 56% | 59% | 64% | 61% | 65% | 66% | 66% | 66% | 67% | 73% | 75% | 73% | 75% | 67% | 75% |
| **Present Value Revenue Requirement (PVRR) [$B][2]** | $35.0 | | $35.3 | | $35.1 | | $35.4 | | $36.3 | | $36.3 | | $45.4 | | $42.8 | | $52.6 | |
| **Average Monthly Residential Bill Impact for a Household Using 1000kWh (by 2030 \| by 2035)[3]** | $13 | $21 | $13 | $22 | $11 | $23 | $12 | $24 | $15 | $23 | $14 | $23 | $33 | $40 | $29 | $37 | $51 | $58 |
| **Average Annual Percentage Change in Residential Bills (through 2030 \| through 2035)[3]** | 1.1% | 1.2% | 1.2% | 1.2% | 1.1% | 1.3% | 1.1% | 1.3% | 1.3% | 1.3% | 1.3% | 1.3% | 2.8% | 2.2% | 2.5% | 2.0% | 4.1% | 2.9% |
| **Total System Solar [MW][4, 5] by 2035** | 5,250 | | 4,950 | | 7,250 | | 7,350 | | 7,350 | | 7,350 | | 9,600 | | 9,600 | | 9,600 | |
| **Incremental Onshore Wind [MW][4] by 2035** | 0 | | 0 | | 900 | | 900 | | 750 | | 750 | | 1,600 | | 1,600 | | 1,600 | |
| **Incremental Offshore Wind [MW][4] by 2035** | 0 | | 0 | | 0 | | 0 | | 0 | | 0 | | 1,300 | | 100 | | 2,500 | |
| **Incremental SMR Capacity [MW][4] by 2035** | 0 | | 0 | | 0 | | 0 | | 0 | | 0 | | 0 | | 700 | | 0 | |
| **Incremental Storage [MW][4, 6] by 2035** | 200 | | 1,250 | | 1,350 | | 1,900 | | 1,400 | | 1,850 | | 1,950 | | 1,950 | | 4,950 | |
| **Incremental Gas [MW][4] by 2035** | 5,350 | | 4,400 | | 4,400 | | 3,950 | | 4,400 | | 3,950 | | 2,150 | | 2,150 | | 0 | |
| **Total Contribution from Energy Efficiency and Demand Response Initiatives [MW][7] by 2035** | 825 | | 825 | | 825 | | 825 | | 825 | | 825 | | 1,500 | | 1,500 | | 1,500 | |
| **Remaining Coal Capacity [MW][4] by 2035** | 0 | | 0 | | 0 | | 0 | | 0 | | 0 | | 0 | | 0 | | 0 | |
| **Coal Retirements** | Most Economic | | Most Economic | | Most Economic | | Most Economic | | Earliest Practicable | | Earliest Practicable | | Earliest Practicable[8] | | Earliest Practicable[8] | | Most Economic[9] | |
| **Dependency on Technology & Policy Advancement** | ◔ | | ◑ | | ◔ | | ◑ | | ◑ | | ◕ | | ◕ | | ● | | ● | |

[1]Combined DEC/DEP System $CO_2$ Reductions from 2005 baseline in Duke's Base Gas Assumption

[2]PVRRs exclude the cost of $CO_2$ as tax. PVRR results reflect Duke's Base Gas and Battery Cost Assumptions

[3]Represents specific IRP portfolio's incremental costs included in IRP analysis; does not include complete costs for other initiatives that are constant throughout the IRP or that may be pending before state commissions

[4]All capacities are Total/Incremental nameplate capacity within the IRP planning horizon

[5]Total solar nameplate capacity includes 2,950 MW connected in DEP as of year-end 2020 (projected)

[6]Includes 4-hr and 6-hr grid-tied storage and storage at solar plus storage sites

[7]Contribution of EE/DR (including Integrated Volt-Var Control (IVVC) and Distribution System Demand Response (DSDR)) in 2035 to peak winter planning hour

[8]Earliest Practicable retirement dates with delaying Roxboro 1&2 to EOY 2029 for integration of offshore wind/SMR by 2030

[9]Most Economic retirement dates with delaying Roxboro 1&2 to EOY 2029 for integration of offshore wind by 2030

**Legend:**

○ Not Dependent
◔ Slightly Dependent
◑ Moderately Dependent
◕ Mostly Dependent
● Completely Dependent

## TABLE 1-C

## DEC/DEP COMBINED SUPPLEMENTAL PORTFOLIOS MODELING RESULTS

<table>
<tr><th></th><th colspan="18">DEP/DEC Combined System</th></tr>
<tr><th>Pathway</th><th colspan="2">A1</th><th colspan="2">A2</th><th colspan="2">B1</th><th colspan="2">B2</th><th colspan="2">C1</th><th colspan="2">C2</th><th colspan="2">D1</th><th colspan="2">E1</th><th colspan="2">F1</th></tr>
<tr><td>System $CO_2$ Reduction (2030 | 2035)[1]</td><td>56%</td><td>55%</td><td>57%</td><td>56%</td><td>59%</td><td>64%</td><td>61%</td><td>65%</td><td>66%</td><td>66%</td><td>66%</td><td>67%</td><td>73%</td><td>75%</td><td>73%</td><td>75%</td><td>67%</td><td>75%</td></tr>
<tr><td>Present Value Revenue Requirement (PVRR) [$B][2]</td><td colspan="2">$78.6</td><td colspan="2">$78.8</td><td colspan="2">$81.6</td><td colspan="2">$82.4</td><td colspan="2">$83.2</td><td colspan="2">$83.8</td><td colspan="2">$100.2</td><td colspan="2">$95.2</td><td colspan="2">$107.2</td></tr>
<tr><td>Total System Solar [MW][3, 4] by 2035</td><td colspan="2">10,500</td><td colspan="2">10,350</td><td colspan="2">15,100</td><td colspan="2">15,600</td><td colspan="2">15,550</td><td colspan="2">15,600</td><td colspan="2">18,350</td><td colspan="2">18,350</td><td colspan="2">18,350</td></tr>
<tr><td>Incremental Onshore Wind [MW][3] by 2035</td><td colspan="2">0</td><td colspan="2">0</td><td colspan="2">1,500</td><td colspan="2">1,500</td><td colspan="2">1,350</td><td colspan="2">1,500</td><td colspan="2">2,850</td><td colspan="2">2,850</td><td colspan="2">2,850</td></tr>
<tr><td>Incremental Offshore Wind [MW][3] by 2035</td><td colspan="2">0</td><td colspan="2">0</td><td colspan="2">0</td><td colspan="2">0</td><td colspan="2">0</td><td colspan="2">0</td><td colspan="2">2,650</td><td colspan="2">250</td><td colspan="2">2,650</td></tr>
<tr><td>Incremental SMR Capacity [MW][3] by 2035</td><td colspan="2">0</td><td colspan="2">0</td><td colspan="2">0</td><td colspan="2">0</td><td colspan="2">0</td><td colspan="2">0</td><td colspan="2">0</td><td colspan="2">1,350</td><td colspan="2">700</td></tr>
<tr><td>Incremental Storage [MW][3, 5] by 2035</td><td colspan="2">600</td><td colspan="2">1,600</td><td colspan="2">1,900</td><td colspan="2">3,400</td><td colspan="2">2,000</td><td colspan="2">3,400</td><td colspan="2">4,350</td><td colspan="2">4,350</td><td colspan="2">7,350</td></tr>
<tr><td>Incremental Gas [MW][3] by 2035</td><td colspan="2">8,850</td><td colspan="2">7,950</td><td colspan="2">7,500</td><td colspan="2">6,100</td><td colspan="2">9,600</td><td colspan="2">8,250</td><td colspan="2">6,400</td><td colspan="2">6,100</td><td colspan="2">0</td></tr>
<tr><td>Total Contribution from Energy Efficiency and Demand Response Initiatives [MW][6] by 2035</td><td colspan="2">2,050</td><td colspan="2">2,050</td><td colspan="2">2,050</td><td colspan="2">2,050</td><td colspan="2">2,050</td><td colspan="2">2,050</td><td colspan="2">3,350</td><td colspan="2">3,350</td><td colspan="2">3,350</td></tr>
<tr><td>Remaining Dual Fuel Coal Capacity [MW][3, 7] by 2035</td><td colspan="2">3,050</td><td colspan="2">3,050</td><td colspan="2">3,050</td><td colspan="2">3,050</td><td colspan="2">0</td><td colspan="2">0</td><td colspan="2">0</td><td colspan="2">0</td><td colspan="2">2,200</td></tr>
<tr><td>Coal Retirements</td><td colspan="2">Most Economic</td><td colspan="2">Most Economic</td><td colspan="2">Most Economic</td><td colspan="2">Most Economic</td><td colspan="2">Earliest Practicable</td><td colspan="2">Earliest Practicable</td><td colspan="2">Earliest Practicable[8]</td><td colspan="2">Earliest Practicable[8]</td><td colspan="2">Most Economic[9]</td></tr>
<tr><td>Dependency on Technology & Policy Advancement</td><td colspan="2">◔</td><td colspan="2">◑</td><td colspan="2">◔</td><td colspan="2">◑</td><td colspan="2">◑</td><td colspan="2">◕</td><td colspan="2">◕</td><td colspan="2">●</td><td colspan="2">●</td></tr>
</table>

[1]Combined DEC/DEP System $CO_2$ Reductions from 2005 baseline in Duke's Base Gas Assumption

[2]PVRRs exclude the cost of $CO_2$ as tax. PVRR results reflect Duke's Base Gas and Battery Cost Assumptions

[3]All capacities are Total/Incremental nameplate capacity within the IRP planning horizon

[4]Total solar nameplate capacity includes 3,925 MW connected in DEC and DEP combined as of year-end 2020 (projected)

[5]Includes 4-hr and 6-hr grid-tied storage, storage at solar plus storage sites, and pumped storage hydro

[6]Contribution of EE/DR (including Integrated Volt-Var Control (IVVC) and Distribution System Demand Response (DSDR)) in 2035 to peak winter planning hour

[7]Remaining coal units are capable of co-firing on natural gas

[8]Earliest Practicable retirement dates with delaying one (1) Belews Creek unit and Roxboro 1&2 to EOY 2029 for integration of offshore wind/SMR by 2030

[9]Most Economic retirement dates with delaying Roxboro 1&2 to EOY 2029 for integration of offshore wind by 2030

**Legend**:

- ○ Not Dependent
- ◔ Slightly Dependent
- ◑ Moderately Dependent
- ◕ Mostly Dependent
- ● Completely Dependent

The resource mixes resulting from Portfolios A1, A2, B1, B2, C1, and C2 for the DEC/DEP combined system show various options to reduce carbon emissions using established and economic technologies. In comparing Portfolios A1/A2 to Portfolios B1/B2, the inclusion of a carbon policy in Portfolios B1/B2 drives significant additional renewable energy, with Portfolios B1/B2 showing an increase in solar of approximately 44%, when compared to Portfolios A1/A2. Portfolios C1/C2 show renewable energy additions similar to Portfolios B1/B2, but more immediate carbon reductions (66% in C1/C2 compared to approximately 60% in B1/B2 by 2030), driven by the accelerated retirement of the DEP's and DEC's (the Companies) coal generation. All of these portfolios rely on new natural gas to support the retirement of coal and the integration of greater volumes of intermittent solar generation. Customer cost impacts measured as Present Value of Revenue Requirements (PVRR) are largely similar across these six portfolios, with the inclusion of the carbon policy driving slightly increased costs in Portfolios B1, B2, C1, and C2, compared to Portfolios A1 and A2.

The resource mixes resulting from Portfolios D1, E1, and F1 for the DEC/DEP Combined System are each unique to the specific technology on which each portfolio focuses. Portfolios D1 and E1 are focused on achieving 70% carbon reduction by 2030, either through offshore wind (Portfolio D1) or advanced nuclear technologies (Portfolio E1). In addition to those technologies, these portfolios include significant levels of solar and storage, but also require new gas generation to enable the expedited retirement of coal to sufficiently reduce carbon emissions within the required time frame. Portfolio F1 assumes no new natural gas is added to the system, and, as a result, shows the significant volume of energy storage resources that is required to ensure reliable service to customers in the absence of other firm, dispatchable resources. PVRR estimates are higher in these portfolios, compared to the PVRR of Portfolios A1-C2, given the early adoption of more expensive emergent technologies that are required to achieve more aggressive carbon reduction objectives (70% by 2030) driving Portfolios D1 and E1 and the elimination of economic natural gas as a resource option in F1. While these Portfolios D1, E1, and F1 are each distinctive, one common characteristic is their reliance on emerging technologies that may not be commercially available or economic within the resource planning window to meet customer demand growth and allow for the reliable replacement of retiring coal generation. As a result, these portfolios are somewhat theoretical or illustrative in nature until meaningful advancements are made in the development of these technologies and maturation of the associated supply chains.

## PREFERRED PORTFOLIO

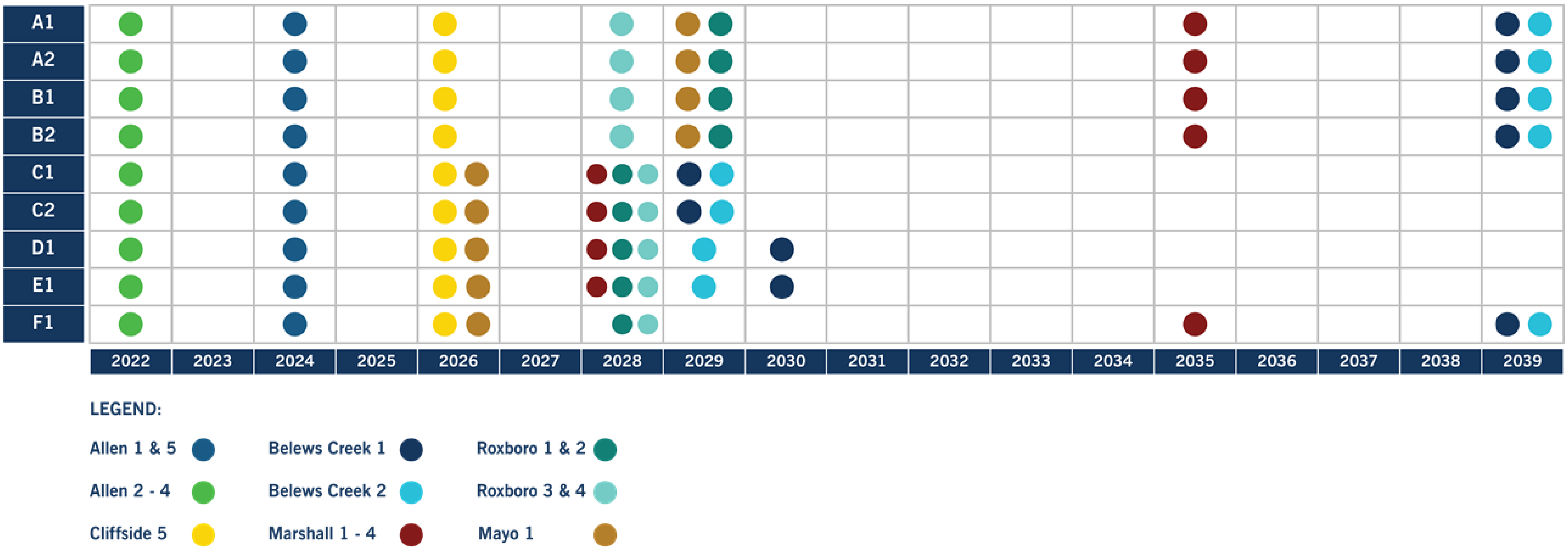
Order No. 2021-447 requires the Company to select a "single portfolio plan . . . as the most reasonable and prudent means of meeting their energy and capacity needs" at the time of the Commission's review. DEP believes that the SC Supplemental Portfolio representing "the most reasonable and prudent plan" should prioritize retirement of the Company's existing coal fleet in the most expeditious manner to accelerate carbon reduction, while ensuring affordability and reliable service for customers. Planning for earliest practicable coal retirements and to transition the Company's generation fleet has become increasingly important due to the likelihood of more stringent environmental regulations, the growing potential for carbon policy, and the ongoing constraints on coal supply. Of the existing portfolios, Portfolio C1 (Modified Earliest Practicable Coal Retirements) is the best representation among the Company's SC Supplemental Portfolios of how to achieve these goals using proven technologies that are economic today. Accordingly, DEP has selected Portfolio C1 as "the most reasonable and prudent plan" at this time, in compliance with the Commission's Order.

Portfolio C1 retains the same objective and approach of Portfolio C from the September 2020 IRP, contemplating a rapid and significant reduction in carbon emissions by retiring all coal generation by 2030 and adding a diverse mix of technologies such as solar, wind, storage and natural gas to meet customers' electricity needs over the planning horizon. As explained in the September 2020 IRP (as relative to Portfolio C), the planning criteria and modeling assumptions underlying Portfolio C1 were intentionally designed to accelerate retirement of DEP's coal-fired generation to the earliest practicable date and do not strictly adhere to conventional least cost planning criteria. In contrast, the economically optimized portfolios retire coal based on an economic analysis, as described in Section 3. Portfolio C1's rapid acceleration of coal retirements is predicated on leveraging existing infrastructure to facilitate the generation transition, taking advantage of transmission capacity, gas pipeline, and access to cooling water at retiring coal sites to expedite the development of replacement generation. It is important to understand that a fundamental tenet of achieving the coal generation retirements and planned new generation additions on the pace and at the scale contemplated by Portfolio C1 is the efficiency created by on-site replacement generation where existing coal units are being retired.

Figure 1-A below shows an illustration of DEP and DEC coal retirements assumed in each of the SC Supplemental Portfolios.

FIGURE 1-A

## DEC/DEP COMBINED SYSTEM COAL RETIREMENTS BY PORTFOLIO




* Cliffside 6 operates at 100% natural gas in all alternate portfolios starting in 2030

The selection of Portfolio C1 should be understood as directional in nature, demonstrating the Company's desire to closely examine pathways to significant, near-term carbon reductions as opposed to a firm commitment to execute a specific resource plan at this point in time. Retirements of the magnitude contemplated under Portfolio C1 will require careful timing and strategy to plan replacement resources, as well as constructive regulatory and policy support.

It is also important to emphasize that the retirement of approximately 10,000 MW of coal generation across the DEC/DEP combined system in an 8-year period would be extraordinary; the Company is not aware of any other utility contemplating retirement of an equally significant volume of firm dispatchable coal generation in this time frame.

## A DIVERSE, FLEXIBLE RESOURCE PORTFOLIO

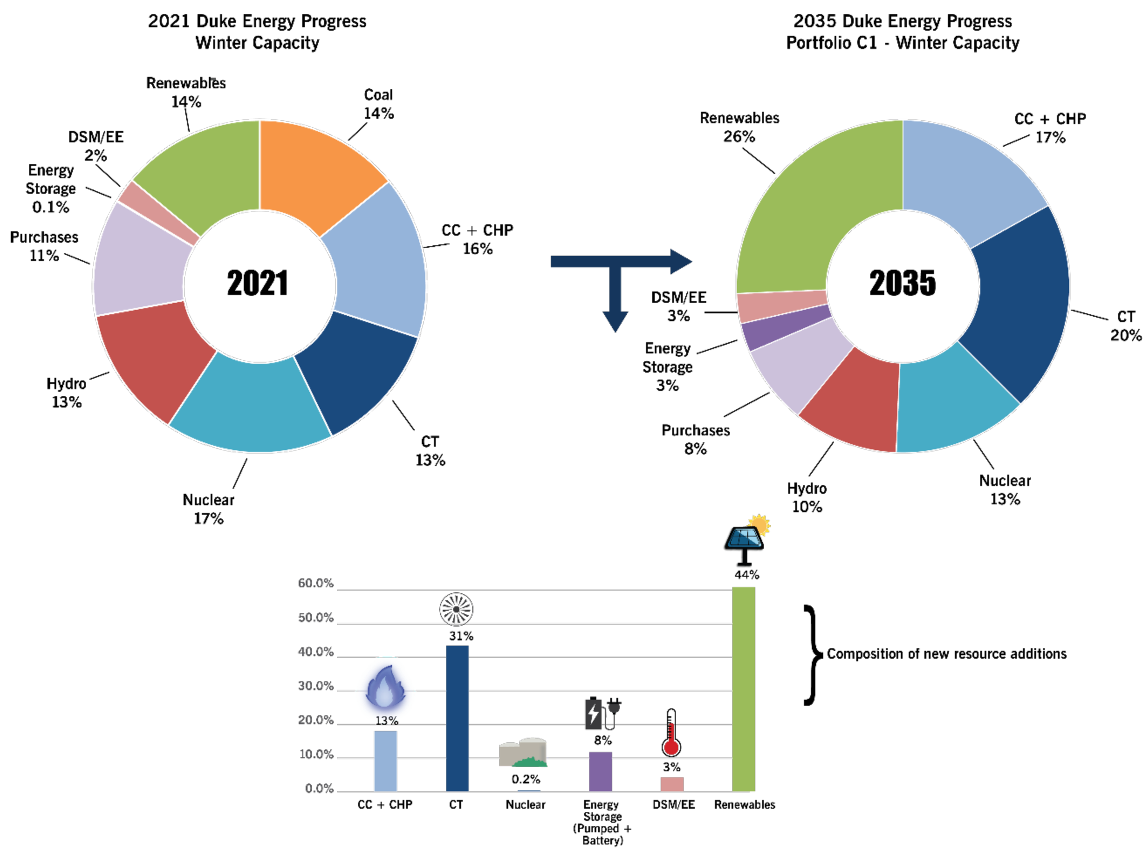
Portfolio C1 includes more than 15,500 MW of solar in the DEC/DEP combined system, which is among the highest level of solar additions of the supplemental portfolios. This would nearly quadruple the amount of solar already on the combined system, which already has installed nationally competitive volumes of solar over the past five years. By 2035, solar generation would comprise approximately 30% of the Companies' nameplate capacity resource mix. This portfolio also results in significant additions of battery storage in the near term and adds onshore wind in the later years of the planning horizon.

To incorporate these high volumes of intermittent, variable generation, it is imperative that flexible resources that are dispatchable over extended periods accompany this near-term transition to replace retiring dispatchable coal generation. To accomplish this transition while ensuring reliable service for customers, Portfolio C1 plans for additions of new natural gas combined cycle and combustion turbines built at the sites of retiring coal facilities to reliably meet customer demand when solar and wind is not available or when their output is diminished. With the potential to utilize hydrogen at these facilities, these resources can support further carbon reduction into the future, while providing the firm, dispatchable generation needed to support the integration of increased intermittent generation.

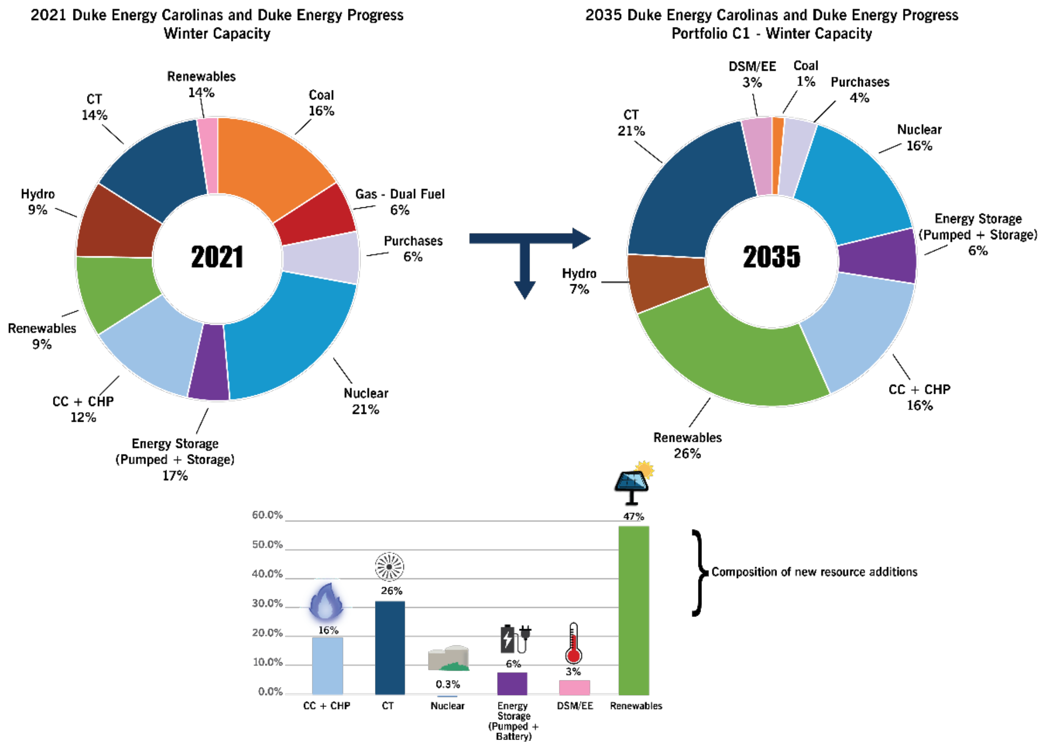
The proportion of new generation resources in this portfolio should be expected to change as more current inputs and possibly new policy direction is integrated into the Companies' planning assumptions. However, barring major policy changes, hydrogen-capable natural gas generators are expected to serve a critical role, enabling economic coal retirements while maintaining system reliability, with a gradual shift in mission over the long term, towards ultimately backstanding renewables and storage.

Figures 1-B and 1-C below show the transition from the 2021 generation resource mix to the 2035 resource mix under Portfolio C1 for DEP and the DEC/DEP Combined System.

## FIGURE 1-B
## DEP 2021 CAPACITY TO 2035 CAPACITY UNDER PORTFOLIO C1



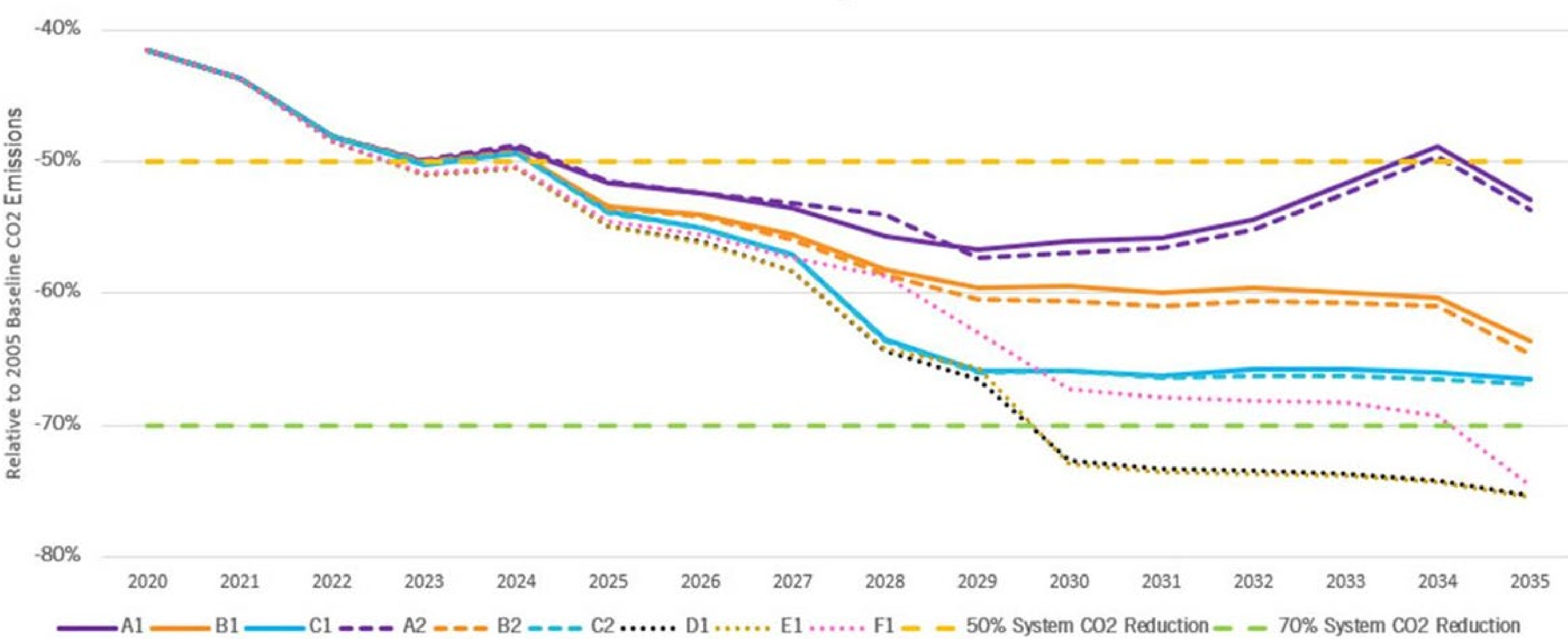
## FIGURE 1-C
## DEC/DEP COMBINED SYSTEM 2021 CAPACITY TO 2035 CAPACITY UNDER PORTFOLIO C1




## SIGNIFICANT CARBON REDUCTIONS BY 2030 USING PROVEN AND ECONOMIC GENERATION RESOURCES

Portfolio C1 contemplates the most significant, immediate, and cost-effective reduction in carbon when comparing the portfolios dependent on technology that is currently viable and economic today. Figure 1-D illustrates the carbon reduction achieved by each of the SC Supplemental Portfolios.

**FIGURE 1-D**
**DEC/DEP COMBINED CARBON REDUCTION BY PORTFOLIO**



In comparing the carbon reductions projected by Portfolios A1, B1, and C1, the significant, early reduction shown by Portfolio C1 is notable. Portfolios D1, E1, and F1 show greater carbon reduction by 2030 than Portfolio C1, but, as explained below, because of their dependence on technologies and industries that are not commercially viable and economic, they are not selected as the Company's "preferred portfolio."

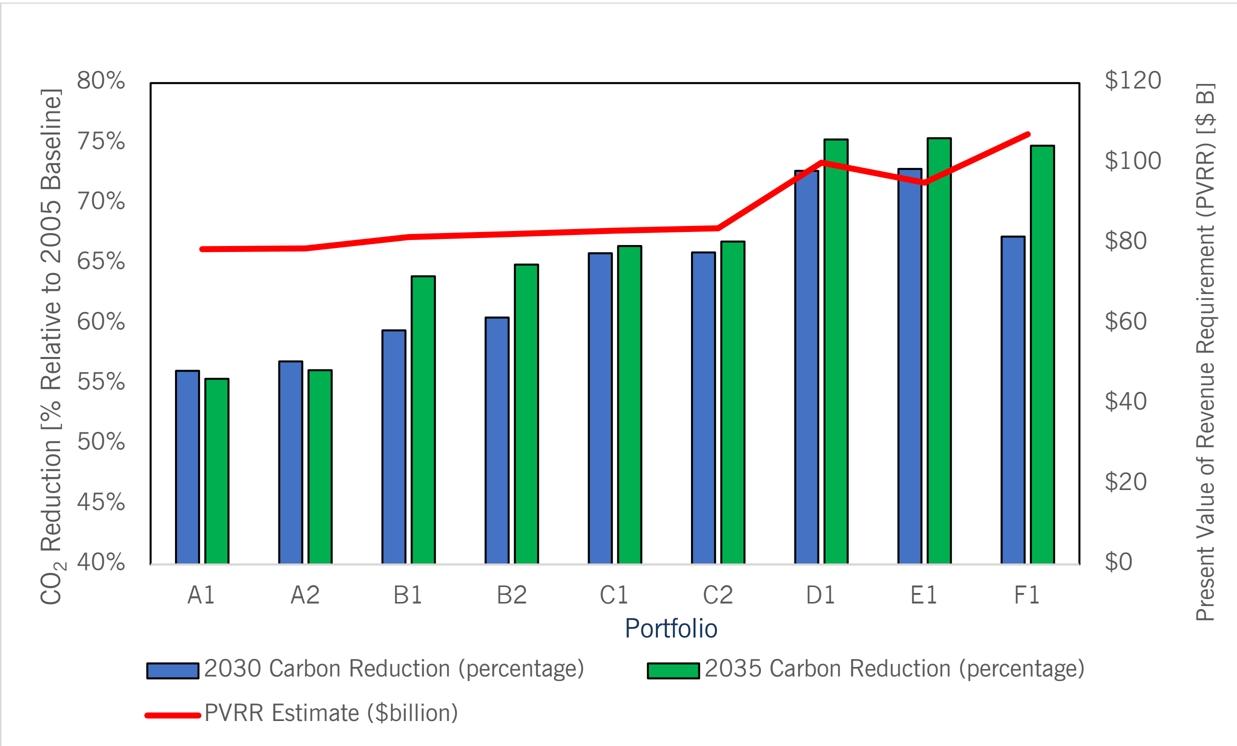
Consistent with Act 62, the Company must determine "the most reasonable and prudent plan," as of "the time the plan is reviewed." At the time of this analysis, it is uncertain whether and/or when offshore wind generation, small modular nuclear reactors, or large-scale adoption of battery storage as a scalable capacity resource will be commercially available and economic. These technologies and industries require advancements in development and maturation to provide a high degree of confidence that it is possible to use them (1) in the scale required, (2) in the location required, and (3) within the time period required to align with the applicable portfolio. The Company is supportive of the continued analysis of these technologies and will continue to evaluate their reasonableness and prudence for inclusion in a preferred portfolio in the future.

Finally, the assumptions in Portfolio C1 are more reasonable and appropriate for resource planning than the more aggressive cost assumptions incorporated in Portfolio A2 or B2 or C2. Specifically, as described in greater detail in Section 2, the Company views the use of a low battery cost forecast, which is by definition less probable than a moderate forecast, as better suited for sensitivity or scenario analysis rather than a base case assumption. Similarly, a natural gas forecast that incorporates an early transition to a fundamental fuel forecast would be inconsistent with actual market information in the way fuel procurement is planned, managed, and accounted for, and thus would not be a prudent base case assumption, but rather better suited as a price sensitivity.

## ESTIMATED PVRR IS REASONABLE

In considering the range of PVRR estimates included in the nine SC Supplemental Portfolios, the PVRR estimated for Portfolio C1 is reasonable. The information provided in Tables 1-A and 1-B above provide the specific PVRR estimates for each portfolio. Figure 1-E below illustrates the relationship between carbon reductions and PVRR for all portfolios. Viewing the range of estimated customer cost impacts and associated anticipated carbon reductions, Portfolio C1 represents a balanced approach to planning for more near-term carbon reductions in a prudent and responsible manner that keeps customer affordability and reliability of service as a priority.

## FIGURE 1-E
## DEC/DEP COMBINED SYSTEM ESTIMATED PVRR AND ASSOCIATED CARBON REDUCTION




## PERFORMS WELL IN VARIOUS GAS AND CARBON PRICE SCENARIOS AND REDUCES RISKS AROUND COAL SUPPLY CONSTRAINTS

As described in greater detail in Section 3, Portfolio C1 was evaluated with all other portfolios across a range of potential future natural gas and carbon price forecasts, including two variations of high, base, and low natural gas forecasts and high, base, and no carbon price scenarios. This analysis presented in Section 3 illustrates that Portfolio C1 performs well relative to other portfolios, especially when viewed against scenarios that consider a future carbon policy. This is meaningful to establish the extent to which Portfolio C1 reduces risk for customers across a range of gas and carbon prices in the future.

Portfolio C1 also addresses significant concerns regarding fuel security issues related to the coal supply chain. DEP is already experiencing coal supply constraints today and expect these constraints to worsen in the future. Coal suppliers are facing challenges due to (1) their deteriorated financial health due to declining demand related to accelerated coal retirements across the utility sector and (2) uncertainty around future federal and state regulations for power plants and mining operations. This risk is further exacerbated by related issues with the railroads that provide coal transportation to coal plants. Diminishing and inconsistent coal demand makes it more costly and difficult for both the railroads and coal suppliers to provide reliable service and responsive deliveries – a trend that will continue to worsen as the industry winds down.

## PREFERRED PORTFOLIO ILLUSTRATES DIRECTION, BUT ADDITIONAL ANALYSIS AND SUPPORTIVE POLICIES ARE NEEDED TO EVALUATE POTENTIAL IMPLEMENTATION OPTIONS

Order No. 2021-447 recognized the fundamental importance and complexity of integrated resource planning and also emphasized that the Company will be required to make a variety of resource planning decisions over the short-term and the long-term. The preferred portfolio is intended to reflect the most reasonable and prudent resource planning path forward at the time of Commission review. DEP's selection of Portfolio C1 as the preferred portfolio reflects the Company's view that near-term, significant carbon emissions reduction utilizing established and economic resources represents "the most reasonable and prudent plan" to meet the Company's future energy and capacity needs. Importantly, selection of Portfolio C1 presents DEP's preferred plan for planning purposes at this time but does not represent a decision to begin executing this specific resource plan today.

Additional analysis is also needed to further evaluate and refine the optimal coal retirement schedule to achieve carbon reductions in the most responsible manner and to continue to analyze generation replacement options that support reliability and balance cost and customer affordability with the more aggressive near-term carbon reductions shown in Portfolio C1. This analysis will include updated inputs and assumptions, as well as revised studies that will inform the Company's resource planning analysis. The Company will also incorporate the Commission's additional directives and requirements for further planning analysis to be included in the Company's 2022 IRP, as set forth in Order No. 2021-447, all of which will be informed by the robust stakeholder participation that the Company will undertake leading up to the 2022 IRP.

This additional resource planning analysis, input from stakeholders in both South Carolina and North Carolina, as well as constructive regulatory and policy support at the state and federal level is imperative to accomplishing the generating fleet transition that will be necessary to achieve the aggressive carbon emission reductions identified in Portfolio C1.

## APPLICABILITY OF PREFERRED PORTFOLIO

The IRP serves a variety of important regulatory purposes beyond informing the Commission and stakeholders and charting a course for future generation resource selections. DEP's selection of Portfolio C1 is limited to fulfilling the specific directive to identify the most reasonable and prudent means for meeting the Company's long-term energy and capacity needs and such selection is not intended to dictate its use as the appropriate plan for all other legal and regulatory purposes that integrated resource planning serves. Other legal and regulatory requirements will inform the Company's use of the IRP for future purposes, such as calculating avoided cost pursuant to PURPA and evaluating the cost effectiveness of EE/DSM programs. The Company will address the appropriate IRP analysis to be applied to future dockets as those issues arise.

## CONCLUSION

Transitioning to a cleaner energy future remains an utmost priority for DEP. To that end, leading into the 2022 IRP, a key focus for DEP is the close evaluation of options to expedite the pace of this transition through accelerated coal retirements, while continuing to provide reliable, affordable service to customers. The SC Supplemental Portfolios and Analysis presented as part of the Company's 2020 SC Modified IRP are consistent with the Commission's Order and provide the Commission with additional information and analysis requested in Order No. 2021-447. Each of the supplemental portfolios has its own benefits and challenges, and no one option establishes "the perfect plan." However, the Company believes that utilizing Portfolio C1 as its Preferred Portfolio appropriately drives the energy transition conversation and related planning in a direction that supports "the most reasonable and prudent means of meeting DEP's energy and capacity needs" today. The development of new public policies and the advancement of new technologies will have a key role in shaping the development of this transition. Stakeholder engagement and collaboration are imperative to informing DEP's upcoming 2022 IRP, and the Company looks forward to continuing collaboration with diverse stakeholders to chart a path forward that balances the pursuit of a clean energy future through accelerated carbon emission reductions, while protecting affordability and reliability for customers.



# 2 RENEWABLE ENERGY AND BATTERY STORAGE MODIFIED INPUTS AND ASSUMPTIONS

The SC Supplemental Portfolios include several modifications to solar energy and battery storage inputs and assumptions, as required by Commission Order No. 2021-447. These modifications are shown in Portfolios A1, A2, B1, B2, C1, C2, D1, E1, and F1, as summarized in Table 2-A below.

## TABLE 2-A
## RENEWABLE ENERGY AND BATTERY STORAGE INPUT AND ASSUMPTION CHANGES

| PORTFOLIO OUTCOME | IRP FILING | IRP PATHWAY | FEDERAL SOLAR INVESTMENT TAX CREDIT EXTENSION | ANNUAL SOLAR INTER-CONNECTION LIMITS [MW] | PERCENT OF FUTURE SOLAR AS SINGLE AXIS TRACKING | $38/MWH SOLAR PPA AS SELECTABLE RESOURCE | BATTERY COST FORECAST |
|---|---|---|---|---|---|---|---|
| Base Case without Carbon Policy | Original | A | No Extension | 500 | 60% | Excluded | Carolinas Specific Forecast |
| | Modified | A1 | Extension | 750 | 100% | Included | Carolinas Specific Forecast |
| | Modified | A2 | Extension | 750 | 100% | Included | 2020 NREL ATB Low Forecast |

| PORTFOLIO OUTCOME | IRP FILING | IRP PATHWAY | FEDERAL SOLAR INVESTMENT TAX CREDIT EXTENSION | ANNUAL SOLAR INTERCONNECTION LIMITS [MW] | PERCENT OF FUTURE SOLAR AS SINGLE AXIS TRACKING | $38/MWH SOLAR PPA AS SELECTABLE RESOURCE | BATTERY COST FORECAST |
|---|---|---|---|---|---|---|---|
| Base Case with Carbon Policy | Original | B | No Extension | 500 | 60% | Excluded | Carolinas Specific Forecast |
| | Modified | B1 | Extension | 750 | 100% | Included | Carolinas Specific Forecast |
| | Modified | B2 | Extension | 750 | 100% | Included | 2020 NREL ATB Low Forecast |
| Earliest Practicable Coal Retirements | Original | C | No Extension | 500 | 60% | Excluded | Carolinas Specific Forecast |
| | Modified | C1 | Extension | 750 | 100% | Included | Carolinas Specific Forecast |
| | Modified | C2 | Extension | 750 | 100% | Included | 2020 NREL ATB Low Forecast |
| 70% $CO_2$ Reduction: Offshore Wind | Original | D | No Extension | 900 | 60% | Excluded | Carolinas Specific Forecast |
| | Modified | D1 | Extension | 900 | 100% | Included | Carolinas Specific Forecast |
| 70% $CO_2$ Reduction: Nuclear SMR | Original | E | No Extension | 900 | 60% | Excluded | Carolinas Specific Forecast |
| | Modified | E1 | Extension | 900 | 100% | Included | Carolinas Specific Forecast |
| No New Gas Generation | Original | F | No Extension | 900 | 60% | Excluded | Carolinas Specific Forecast |
| | Modified | F2 | Extension | 900 | 100% | Included | Carolinas Specific Forecast |

## FEDERAL SOLAR INVESTMENT TAX CREDIT EXTENSION

At the time the September 2020 IRP was developed, the federal solar investment tax credit (ITC) was scheduled to continue phasing down each year until 2022. In the September 2020 IRP, the ITC was modeled consistent with federal law in existence at the time the inputs and assumptions were developed. In December 2020, Congress approved a two-year extension of the solar ITC, and in Commission Order No. 2021-447, the Commission required the Companies to modify their modeling assumptions to reflect the extension of the solar ITC. As a result, DEC and DEP have included the extended solar ITC in modeling for all SC Supplemental Portfolios. Legislative action on tax credits for renewable energy technologies is evolving rapidly and the Companies will continue to reflect the most current policies enacted at the time inputs are gathered for future IRPs.

## SOLAR INTERCONNECTION LIMITATION

In the September 2020 IRP, DEC and DEP included a collective 500 MW limitation on the volume of new solar resources that could be added in each year. In Order No. 2021-447, the Commission required DEC and DEP to modify these modeling assumptions to include an annual interconnection limitation of 750 MW. Accordingly, in Portfolios A1, A2, B1, B2, C1, and C2, DEC and DEP have expanded the annual interconnection limit to 750 MW, which includes 450 MW for DEC and 300 MW for DEP. The volumetric division between DEC and DEP is appropriate based on the saturation of solar in the DEP territory and the future solar development that is expected in both utilities. This is also equivalent to the proportional split between DEC and DEP in the September 2020 IRP. The annual interconnection limit in Portfolios D1, E1, and F1 remains 900 MW.

The 500 MW interconnection limitation in the September 2020 IRP was based on the actual average volume of solar the Companies have interconnected since 2014. The Companies have not achieved 750 MW of solar interconnections in a year previously and most recently achieved 320 MW of new solar interconnections in 2020. Accordingly, it is uncertain whether this amount of solar can be interconnected on an annual basis. The Companies will continue to monitor the pace and volume of new solar interconnections and adjust this modeling assumption in future IRPs.

## $38/MWH SOLAR PPA OPTION

Order No. 2021-447 requires the Companies to include a solar PPA option as a selectable resource in the IRP. All of the SC Supplemental Portfolios include a solar PPA option priced at $38/MWh for a 20-year contract term. The Commission has required modeling at this price point based on the average price of successful bids in Tranche 1 of the CPRE program created pursuant to North Carolina law; however DEC's and DEP's ability to actually procure solar in the future at this price point is uncertain and will depend on future statutory and regulatory action.

In addition to the necessary future policy changes to facilitate any future solar procurement, several factors call into question the likelihood of actually acquiring the volumes of $38/MWh third-party solar shown in the SC Supplemental Portfolios. First, the volume of solar that could be procured at $38/MWh in the DEC/DEP services areas is uncertain. Notably, of the approximately 1,200 MW of solar resources procured over the first two tranches of the NC CPRE Program, approximately one-half of those resources were contracted at, or below, $38/MWh. Numerous factors, such as the competitive procurement structure and locational-specific costs (land availability/property taxes), can impact the cost-effectiveness and depth of market for new solar procurement. For example, existing laws governing renewable energy procurements conducted in the Companies' service area limit projects to Qualifying Facilities (80 MW and under) under PURPA, while such limitations may not exist in other jurisdictions. Additionally, while the Company projects declining solar technology costs into the future, DEC and DEP also expect upward pressure on procurement bid prices as the solar ITC steps down and as it becomes more difficult to find solar facility sites that can cost-effectively accommodate larger project sizes and provide minimal interconnection costs. Said simply, the greater the solar saturation on the DEC and DEP systems, the harder it is to find inexpensive land with low interconnection costs.

In order to provide a balanced portfolio of solar generation across the planning horizon and in recognition of the uncertainty of the volume of solar PPAs that would be available on an annual basis under the prescribed parameters, the Companies divided the annual amount of utility cost-of-service (COS) solar and $38/MWh third-party PPA solar that can be connected to 375 MW each (50 percent of the 750 MW solar interconnection limit). The Companies believe this balance between third-party solar and utility COS-solar is appropriate to ensure a diverse mix of renewable resource types available to customers. It would be imprudent to rely entirely on purchased power for any one resource type, including solar. Finally, the total volume of new third-party solar selected over the 15-year planning horizon is over 3,400 MW, which is significant. For comparison, this is far in excess of the 400 MW (total, not annual) of third-party solar allowed to be selected in the applicable DESC resource plans included in DESC's most recent Modified IRP.

## FIXED TILT VS SINGLE AXIS TRACKING SOLAR CONFIGURATIONS

In the September 2020 IRP, DEC and DEP assumed that 60% of new solar additions would be single-axis tracking and 40% would be fixed tilt. Since the time that those modeling assumptions were developed, updated results of CPRE Tranche 2 are available, which strongly indicate that new solar resources are most likely to be developed as single-axis tracking. In Order No. 2021-447, the Commission required DEC and DEP to modify these modeling assumptions to assume all future solar would be single-axis tracking. Accordingly, all of the SC Supplemental Portfolios reflect this change. The Companies will continue to monitor trends in the solar industry and make adjustments to solar technology assumptions as conditions warrant.

## NREL ANNUAL TECHNOLOGY BASELINE (ATB) ADVANCED BATTERY COSTS

Order No. 2021-447 requires the Companies to conduct analysis using the NREL Annual Technology Baseline (ATB) Low, or Advanced[1], case for battery storage in the IRP. SC Supplemental Portfolios A2, B2, and C2 utilize the 2020 NREL ATB Advanced price forecast for battery storage. The remaining SC Supplemental Portfolios rely on the Companies' internally generated battery storage cost forecasts from the September 2020 IRP that are representative of the costs to build and operate battery storage on the DEP system. Given the rapidly evolving nature of battery technologies, and to promote transparency of costs used in modeling battery storage, the Company is evaluating using published resources, such as the NREL ATB Moderate price forecast, as a starting point for battery storage costs in future IRPs.

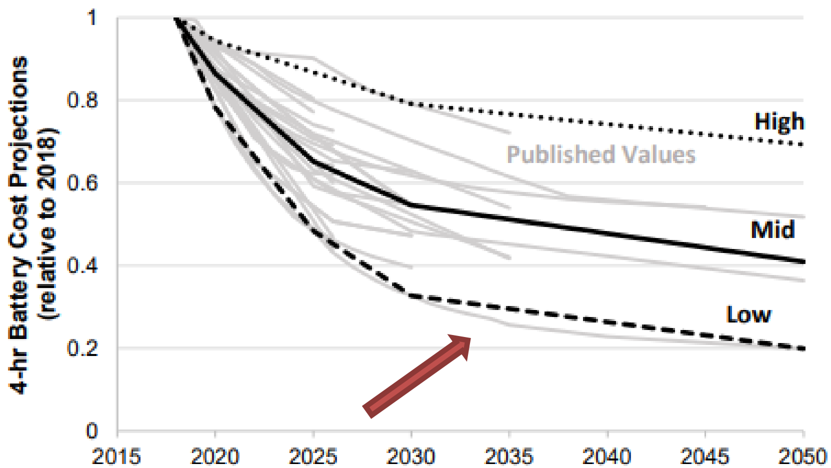
The NREL ATB Advanced cost assumption was not used in all portfolios because there are substantial reasons to question its validity for use as a base planning assumption. The assumed cost declines of the "Advanced" case are exceedingly aggressive and are neither reasonable nor prudent for use as a base assumption for long-term planning.

As shown in Figure 2-A below, NREL's low cost projection aligns with the most aggressive cost decline projection from 19 published sources that were evaluated in NREL's "Cost Projections for Utility-Scale Battery Storage: 2020 Update" which was the basis of the 2020 NREL ATB[2].

[1] In the 2020 NREL ATB, the Low, Mid, and High naming convention for the technology costs was changed to Advanced, Moderate, and Conservative, respectively.
[2] Cole, Wesley, and A. Will Frazier. 2020. Cost Projections for Utility-Scale Battery Storage: 2020 Update. Golden, CO: National Renewable Energy Laboratory. NREL/TP-6A20-75385. https://www.nrel.gov/docs/fy20osti/75385.pdf

FIGURE 2-A

FIGURE ES-1 FROM NREL'S "COST PROJECTIONS FOR UTILITY-SCALE BATTERY STORAGE: 2020 UPDATE" REPORT SHOWING HIGH, MID, LOW BATTERY NORMALIZED BATTERY COSTS COMPARED TO NORMALIZED PUBLISHED VALUES




As shown above, the ATB Moderate/Mid case is more reflective of a median projection for future battery costs. Consistent with the Companies' position that the ATB Moderate case is more reasonable and likely, NREL has explained that "the Moderate Scenario is the most likely projection based on literature and analysis."[3]

Furthermore, NREL has consistently increased its ATB low case cost over the past three years. The NREL ATB began including battery storage costs in 2019, and in the subsequent annual updates, the "Low" case has continually increased in price as shown in Table 1. For storage costs in 2023, the 2020 ATB Advanced case was 5.9% higher than the 2019 version of the forecast, while the 2021 ATB Advanced case was 7.4% higher than the 2020 version. This increase in price of NREL's ATB Advanced estimates signals that the low or Advanced case has been overly aggressive.

[3] Augustine, Chad, and Nate Blair. *Energy Storage Futures Study: Storage Technology Modeling Input Data Report.* Golden, CO: National Renewable Energy Laboratory. NREL/TP-5700-78694. https://www.nrel.gov/docs/fy21osti/78694.pdf

### TABLE 2-B
### COMPARISON OF PRICE OF 4-HOUR BATTERY STORAGE IN NREL ATB ADVANCED CASE FROM 2019, 2020, AND 2021

| $/kw (Real 2021$) | 2021 | 2023 | 2025 | 2027 |
|---|---|---|---|---|
| 2019 ATB | $1,156 | $965 | $773 | $673 |
| 2020 ATB | $1,204 | $1,022 | $839 | $748 |
| 2021 ATB | $1,313 | $1,097 | $881 | $764 |

Using the moderate battery cost assumptions for battery storage aligns with the Company's cost projections for all other technologies evaluated in the IRP, which are based on median cost decline curves. When all technology cost forecasts are median forecasts, using a forecast for a technology that is based on projections that are more or less aggressive than the median forecast causes inconsistencies in the resource selection process which can favor certain technologies. For these reasons, such high and low forecasts are best used for sensitivity analysis in long term resource planning.

In addition to the overly aggressive projected cost declines projected in the NREL ATB Low cost scenario, the Company is concerned that the NREL ATB initial costs do not capture the full costs to construct and operate battery storage on the Company's system. Some areas that may not be incorporating the full cost of installation include safety enhancements, control system design, and long-term reliability requirements.

Given these factors, the Company believes the internally developed battery storage cost projects were reasonable and prudent for planning purposes in the September 2020 IRP submittal, as well as in this supplemental filing. However, as stated previously, the Company has utilized the ordered NREL ATB low cost assumptions for SC Supplemental Portfolios A2, B2, and C2 and is also evaluating using published resources, such as the NREL Moderate case, as a starting point for battery storage costs in future IRPs.

## PORTFOLIO C1 RENEWABLE ENERGY AND BATTERY STORAGE RESULTS

Given the Companies' selection of Portfolio C1 as the Preferred Portfolio, the results shown herein are focused on Portfolio C1. More comprehensive information regarding resource additions across other supplemental portfolios is provided in Section 4.

Table 2-C summarizes the cumulative amount of renewables from Portfolio C1. The data is presented on a "beginning of year" basis and includes 0.5% annual degradation of solar capacity.

## TABLE 2-C
## DEP PORTFOLIO C1 RENEWABLE ENERGY RESOURCE ADDITIONS

| DEP RENEWABLES - COMPLIANCE + NON-COMPLIANCE | | | | | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| | MW NAMEPLATE | | | | | MW CONTRIBUTION TO SUMMER PEAK | | | | | MW CONTRIBUTION TO WINTER PEAK | | | | |
| | SOLAR ONLY | SOLAR WITH STORAGE | BIOMASS / HYDRO | WIND | TOTAL | SOLAR ONLY | SOLAR WITH STORAGE | BIOMASS/ HYDRO | WIND | TOTAL | SOLAR ONLY | SOLAR WITH STORAGE | BIOMASS/ HYDRO | WIND | TOTAL |
| 2021 | 2,888 | 0 | 284 | 0 | 3,171 | 358 | 0 | 284 | 0 | 642 | 17 | 0 | 284 | 0 | 301 |
| 2022 | 3,144 | 0 | 146 | 0 | 3,291 | 409 | 0 | 146 | 0 | 555 | 24 | 0 | 146 | 0 | 170 |
| 2023 | 3,430 | 0 | 135 | 0 | 3,565 | 464 | 0 | 135 | 0 | 599 | 32 | 0 | 135 | 0 | 168 |
| 2024 | 3,716 | 14 | 131 | 0 | 3,861 | 511 | 5 | 131 | 0 | 647 | 41 | 3 | 131 | 0 | 175 |
| 2025 | 4,000 | 13 | 131 | 0 | 4,145 | 557 | 5 | 131 | 0 | 693 | 48 | 3 | 131 | 0 | 183 |
| 2026 | 4,352 | 13 | 120 | 0 | 4,485 | 614 | 5 | 120 | 0 | 739 | 58 | 3 | 120 | 0 | 182 |
| 2027 | 4,481 | 88 | 120 | 0 | 4,690 | 635 | 35 | 120 | 0 | 789 | 62 | 22 | 120 | 0 | 204 |
| 2028 | 4,610 | 163 | 116 | 0 | 4,889 | 655 | 64 | 116 | 0 | 836 | 66 | 41 | 116 | 0 | 222 |
| 2029 | 4,738 | 237 | 60 | 0 | 5,035 | 676 | 93 | 60 | 0 | 830 | 69 | 59 | 60 | 0 | 188 |
| 2030 | 4,915 | 286 | 43 | 0 | 5,244 | 705 | 113 | 43 | 0 | 861 | 74 | 71 | 43 | 0 | 188 |
| 2031 | 5,241 | 334 | 43 | 0 | 5,619 | 758 | 133 | 43 | 0 | 934 | 83 | 84 | 43 | 0 | 210 |
| 2032 | 5,516 | 333 | 42 | 150 | 6,040 | 802 | 133 | 42 | 12 | 989 | 91 | 83 | 42 | 53 | 268 |
| 2033 | 5,639 | 481 | 42 | 300 | 6,462 | 822 | 195 | 42 | 24 | 1,083 | 94 | 120 | 42 | 105 | 361 |
| 2034 | 5,763 | 629 | 41 | 450 | 6,883 | 842 | 257 | 41 | 36 | 1,176 | 98 | 157 | 41 | 158 | 454 |
| 2035 | 5,885 | 776 | 41 | 600 | 7,302 | 862 | 318 | 41 | 48 | 1,270 | 101 | 194 | 41 | 210 | 546 |

Data presented on a year beginning basis. Solar includes 0.5% per year degradation. Capacity listed excludes REC only contracts. Solar contribution to peak based on 2018

As shown above, by the end of the planning horizon, DEP is projecting approximately 7,300 MW of solar and wind resources on its system. The contribution of these resources towards meeting DEP's winter peak demand is approximately 545 MW by 2035.

Similar to the September 2020 IRP, solar that is forced into each portfolio is represented as either designated, mandated, or undesignated based on the definitions below:

- **Designated:** Facilities with executed contracts (included as "Designated" for the duration of the purchase power contract).

- **Mandated:** Capacity that is not yet under contract but is required through renewable energy programs driven by existing law (examples include future tranches of CPRE, the renewable energy procurement program for large customers, and community solar under NC HB 589 as well as SC Act 236).

- **Undesignated:** Additional capacity projected beyond what is already designated or mandated. Expiring solar contracts are assumed to be replaced in kind with undesignated solar additions. Such additions may include existing facilities or new facilities that enter into contracts that have not yet been executed. As described in the September 2020 IRP, the Companies assumed that there would be some materialization of solar from the interconnection queues above and beyond the capacity classified as "Mandated."

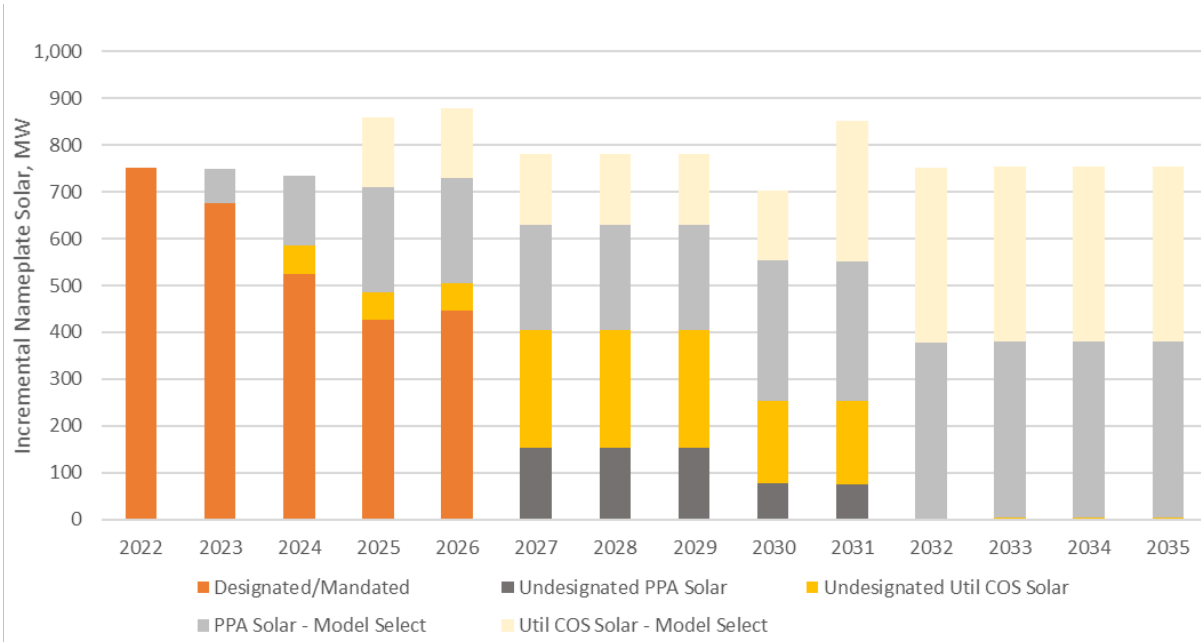
The volume of solar included as Designated, Mandated, and Undesignated in the SC Supplemental Portfolios is the same as that which was included for the September 2020 IRP.

Figure 2-B summarizes the incremental annual additions of solar in Portfolio C1. It is anticipated that a portion of the solar additions classified as Undesignated Solar will be third-party PPA solar materializing from the interconnection queue, as shown in Table Y-2. In years where Designated, Mandated, and Undesignated solar are included, the availability of model-selected solar (both $38/MWh PPA and utility COS) decreases, in order to maintain the 750 MW interconnection limitation. For example, in 2023, the Companies have forecasted approximately 675 MW of Designated/Mandated solar, which leaves 75 MW to be selected by the model. As seen below, the

model selects the $38/MWh third party solar resource option for 75 MW to reach the 750 MW interconnection limit.[4]

## FIGURE 2-B
## DEC & DEP PORTFOLIO C1 INCREMENTAL SOLAR ADDITIONS

### PORTFOLIO C1 INCREMENTAL SOLAR ADDITIONS




[4] In some years the total nameplate capacity of solar exceeds 750 MW. This occurs because the model selects solar in 75 MW increments, and if, at any point, the amount of solar is less than the 450 MW limit in DEC and/or the 300 MW limit in DEP, the model can select an additional unit even if selecting that solar causes the model to exceed 450 MW or 300 MW in DEC and DEP respectively.



# 3 QUANTITATIVE ANALYSIS OF THE SC SUPPLEMENTAL PORTFOLIOS

This section provides an overview of the Company's quantitative analysis of the SC Supplemental Portfolios. Inputs from the September 2020 IRP and modified inputs from the Commission's Order informed the development of the nine supplemental portfolios described herein. The various nine supplemental portfolios were developed to achieve outcomes such as minimizing cost to customers, accelerating coal retirements to their earliest practicable retirement dates, achieving 70% $CO_2$ reductions for the combined Carolinas system, and transitioning the generation fleet without deploying new gas generation. Each of the nine portfolios was then evaluated under eighteen scenarios with varying combinations of fuel prices and $CO_2$ constraints in order to assess trade-offs between cost and carbon reductions, while considering opportunities for and barriers to the portfolio's transition. The analysis considered the cost to customers, resource diversity, reliability, and the long-term carbon intensity of the system. All of the portfolios presented in the 2020 SC Modified IRP are potential paths forward, with optimality depending on future federal and state policies, technology advancements, and cost trajectories. This analysis led to the selection of Portfolio C1 as the "preferred portfolio," as required by the Commission's Order and as described more fully in Section 1.

## OVERVIEW OF ANALYTICAL PROCESS

This supplemental IRP analysis follows the same analytical process used in the September 2020 IRP. While some of the input assumptions have been updated for this supplemental IRP analysis, the analytical process remains consistent and includes the addition of the selection of a preferred portfolio following the analysis.

The analytical process consists of seven steps:

1. Evaluate economic selection of coal plant retirement dates

2. Assess resource needs
3. Identify and screen resource options for further consideration
4. Development of economically optimized portfolios and sensitivity analysis
5. Development of alternative portfolio configurations
6. Perform portfolio scenario analysis
7. Selection of a preferred portfolio

## 1. EVALUATE ECONOMIC SELECTION OF COAL PLANT RETIREMENT DATES

Coal retirements were evaluated and the most economic retirement dates were determined in the September 2020 IRP. The coal retirement dates used in the supplemental IRP analysis are the same as those determined in the September 2020 IRP. The September 2020 IRP provides more detailed information regarding coal retirement dates.

Consistent with the methodology used in the September 2020 IRP, each of the supplemental economically optimized portfolios uses the same most economic coal retirement dates, consistent with those as filed in the September 2020 IRP.

Duke will further evaluate coal retirements and perform a new comprehensive coal retirement analysis to inform the development of the Company's next comprehensive IRP in 2022 (Ordering paragraph 7).

## 2. ASSESS RESOURCE NEEDS

The supplemental IRP analysis uses the same resource assessment to meet system demand and reserve requirements as used in the September 2020 IRP. More information about assessing resource needs can be found in the September 2020 IRP.

## 3. IDENTIFY AND SCREEN RESOURCE OPTIONS FOR FURTHER CONSIDERATION

The supplemental IRP process follows the same resource evaluation as used in the September 2020 IRP to determine how energy efficiency (EE), demand-side management (DSM) and traditional and non-traditional supply-side options may serve customer energy and capacity needs. The Company's EE and DSM projections from the September 2020 IRP, based on existing EE/DSM program experience, the 2020 market potential study, input from its EE/DSM collaborative and cost-effectiveness screening, are used in the supplemental IRP analysis. Similarly, the same supply-side technology options reflecting a diverse mix of technologies and fuel sources (gas, nuclear, renewables, and energy storage) are selectable to meet the remaining resource need to reliably serve customer demand.

## RESOURCE OPTIONS

### ENERGY EFFICIENCY AND DEMAND-SIDE MANAGEMENT

The EE and DR/DSM forecasts used in the September 2020 IRP are used in the SC Supplemental Portfolios and Analysis. More information on the EE and DR/DSM forecasts can be found in the September 2020 IRP.

Future Market Potential Studies (MPS) will incorporate the utility cost test (UCT) as the cost effectiveness measure for use in future IRPs (Ordering paragraph 2). Duke will work with the EE/DSM Planning Collaborative on market acceptance rates of existing technologies, emerging technologies in EE/DSM, and identify which recommendations were not adopted when developing the MPS for future IRPs (Ordering paragraph 3). Duke will also evaluate high and low EE/DSM cases across a range of fuel and $CO_2$ assumptions to better understand what level of EE/DSM should be implemented if fuel costs rise or higher $CO_2$ costs are imposed (Ordering paragraph 4).

### SUPPLY-SIDE

The same supply-side resources were utilized in the supplemental IRP analysis as were used in the September 2020 IRP.

However, the supplemental IRP analysis does incorporate some changes to the input assumptions for these selectable resources. As discussed in Section 2, the SC Supplemental Portfolios incorporate the Federal Investment Tax Credit (ITC) extension on solar development as passed in December 2020, after the filing of the September 2020 IRP (Ordering paragraph 14). The supplemental IRP analysis also includes a $38/MWh solar PPA as a selectable resource (Ordering paragraph 11). Facilities delivering power under these PPAs are assumed to have operational characteristics identical to CPRE projects (Ordering paragraph 12). Furthermore, all future solar is modeled as single-axis tracking solar, rather than the mix of fixed-tilt and single-axis tracking solar used in the September 2020 IRP (Ordering paragraph 15). Finally, and as discussed in Section 2, the Company evaluated the selection of batteries using the NREL ATB Advanced (or "Low") price forecast (Ordering paragraph 16).

# 4. DEVELOPMENT OF ECONOMICALLY OPTIMIZED PORTFOLIOS AND SENSITIVITY ANALYSIS

This section identifies and discusses key variables and assumptions used throughout the supplemental IRP analysis and associated portfolio development. This section also describes the sensitivity analysis conducted to assess the impacts of changes to these variables as well as assumptions used for economically optimized portfolios.

## VARIABLES CONSIDERED IN SENSITIVITY & PORTFOLIO ANALYSIS

Each portfolio is shaped by different input assumptions. The Company's SC Supplemental Portfolios include several input assumptions changes to the September 2020 IRP base planning portfolios, which create Portfolios A1, A2, B1, and B2. Additionally, variables were adjusted to quantify uncertainty and opportunity via sensitivity analysis of the economically optimized portfolios. These key variables and assumption changes are outlined in this subsection.

## LOAD FORECAST

In compliance with the Commission's Order, the Company developed alternative load forecast sensitivities, accounting for economic and other types of uncertainty over the IRP planning horizon. These long-term economic load forecast scenarios are described below. Future IRPs will also evaluate the level of uncertainty to be consistent with the Company's Resource Adequacy study (Ordering paragraph 1).

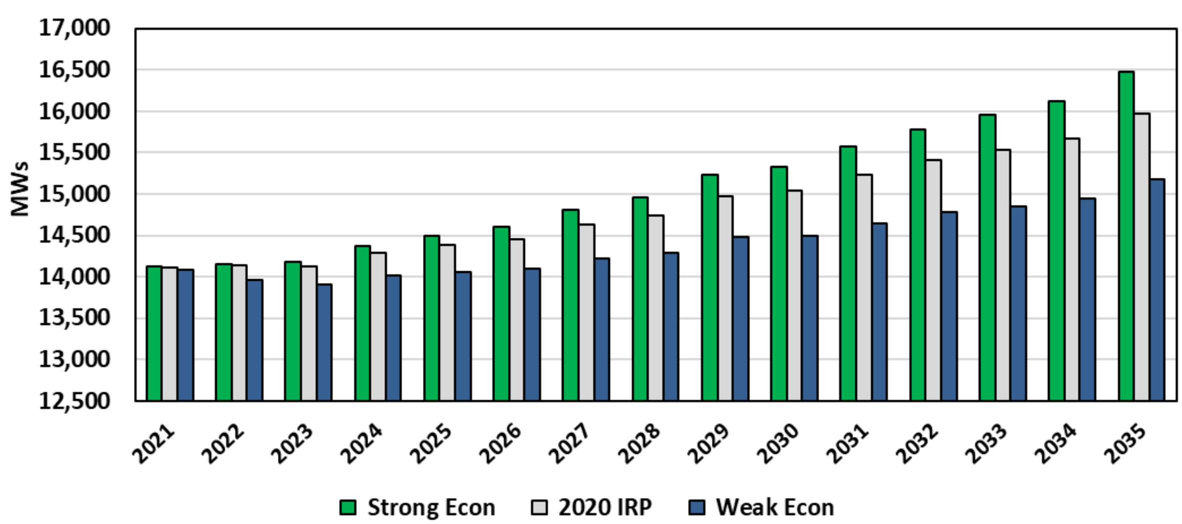
## LONG-TERM ECONOMIC SCENARIOS

In the September 2020 IRP, the Company developed high and low load forecasts based on near-term growth and recession scenarios based on Moody Analytics short-term economic scenarios. These scenarios were intended to capture the effects of possibilities in which the economy either significantly outperforms or underperforms expectations over the next thirty months. The supplemental IRP analysis includes Long-Term Economic Scenarios as a supplement to what was presented in the

September 2020 IRP. In order to create a longer-term variance in economic outcomes, the Company performed an adjustment to each relevant baseline data series by changing the annual growth rates. For the "high economic" scenario, long-term growth rates were increased by a fixed increase of 0.3 percentage points per year, while the "low economic" scenario incorporated a downward adjustment of the same amount. These adjusted economic drivers—which represent long-term, sustained economic over-performance (or under-performance)—were then used to develop new long-term sales and peak forecasts.

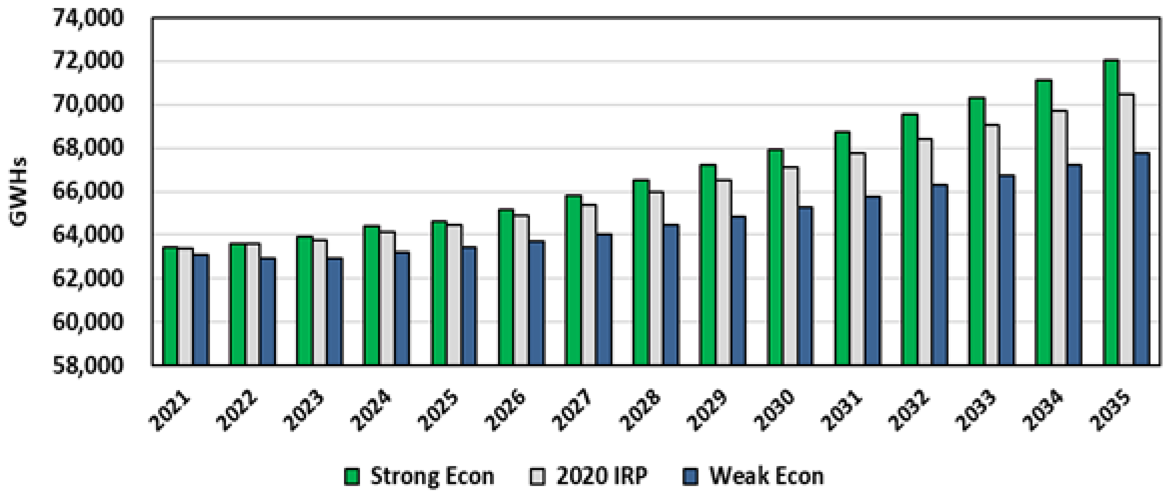
The Long-Term Economic Scenarios resulted in additional strength and weakness compared to the original high and low September 2020 IRP load forecasts. These results are summarized in Figures 3-A and 3-B, and Table 3-A below.

### FIGURE 3-A
### DEP LONG-TERM ECONOMIC SCENARIO - ANNUAL PEAK IMPACTS



ELECTRONICALLY FILED - 2021 August 27 7:35 PM - SCPSC - Docket # 2019-225-E - Page 39 of 115

FIGURE 3-B
DEP LONG-TERM ECONOMIC SCENARIOS - ENERGY SALES IMPACTS



## TABLE 3-A
## DEP LONG-TERM ECONOMIC SCENARIOS - RESULTS SUMMARY

**Load Forecast - Long Term Economic Scenario (Strong and Weak Economics)**

| YEAR | PEAK Strong Econ (MW) | PEAK Weak Econ (MW) | ENERGY Strong Econ (GWH) | ENERGY Weak Econ (GWH) |
|---|---|---|---|---|
| 2021 | 14,129 | 14,081 | 63,404 | 63,080 |
| 2022 | 14,155 | 13,965 | 63,604 | 62,917 |
| 2023 | 14,176 | 13,903 | 63,911 | 62,967 |
| 2024 | 14,370 | 14,016 | 64,387 | 63,196 |
| 2025 | 14,495 | 14,062 | 64,647 | 63,426 |
| 2026 | 14,603 | 14,094 | 65,190 | 63,692 |
| 2027 | 14,813 | 14,224 | 65,799 | 64,037 |
| 2028 | 14,960 | 14,296 | 66,520 | 64,477 |
| 2029 | 15,237 | 14,478 | 67,193 | 64,853 |
| 2030 | 15,331 | 14,497 | 67,933 | 65,290 |
| 2031 | 15,573 | 14,646 | 68,721 | 65,776 |
| 2032 | 15,785 | 14,776 | 69,553 | 66,305 |
| 2033 | 15,952 | 14,856 | 70,323 | 66,756 |
| 2034 | 16,127 | 14,942 | 71,142 | 67,239 |
| 2035 | 16,480 | 15,176 | 72,019 | 67,765 |
| Avg. Annual Growth Rate | 1.1% | 0.5% | 0.9% | 0.5% |

## IMPACT OF POTENTIAL CARBON CONSTRAINTS

The impacts of potential carbon constraints in the supplemental IRP analysis are consistent with the September 2020 IRP, which provides detailed information on carbon policy and proxy price forecasts. Consistent with the September 2020 IRP, the base carbon price forecast was used to reflect a proxy carbon policy in developing the economically optimized Portfolios B1 and B2. The base and high carbon prices were also used in scenario analysis to evaluate how all portfolios would perform under varying carbon policies.

## ENERGY EFFICIENCY AND DEMAND RESPONSE/DEMAND SIDE MANAGEMENT

The assumptions and sensitivity analysis for EE and DR/DSM are consistent with the September 2020 IRP. The September 2020 IRP provides more detailed information regarding EE and DR/DSM.

## SOLAR, SOLAR + STORAGE, AND WIND GENERATION

The high, base, and low renewables capacity forecasts used as inputs to the supplemental IRP analysis are consistent with the September 2020 IRP. The September 2020 IRP provides more detailed information regarding renewables forecasts.

As discussed in Section2, the supplemental IRP analysis increases the solar interconnection limit from 500 MW/year to 750 MW/year for the combined DEP and DEC system for use in the economically optimized portfolios (Ordering paragraph 17). The high renewables forecast sensitivity increased the annual limit to 900 MW/year, while the low renewables forecast sensitivity reduced the limit to 500 MW/year, consistent with the average amount of solar the Companies have interconnected in recent years.

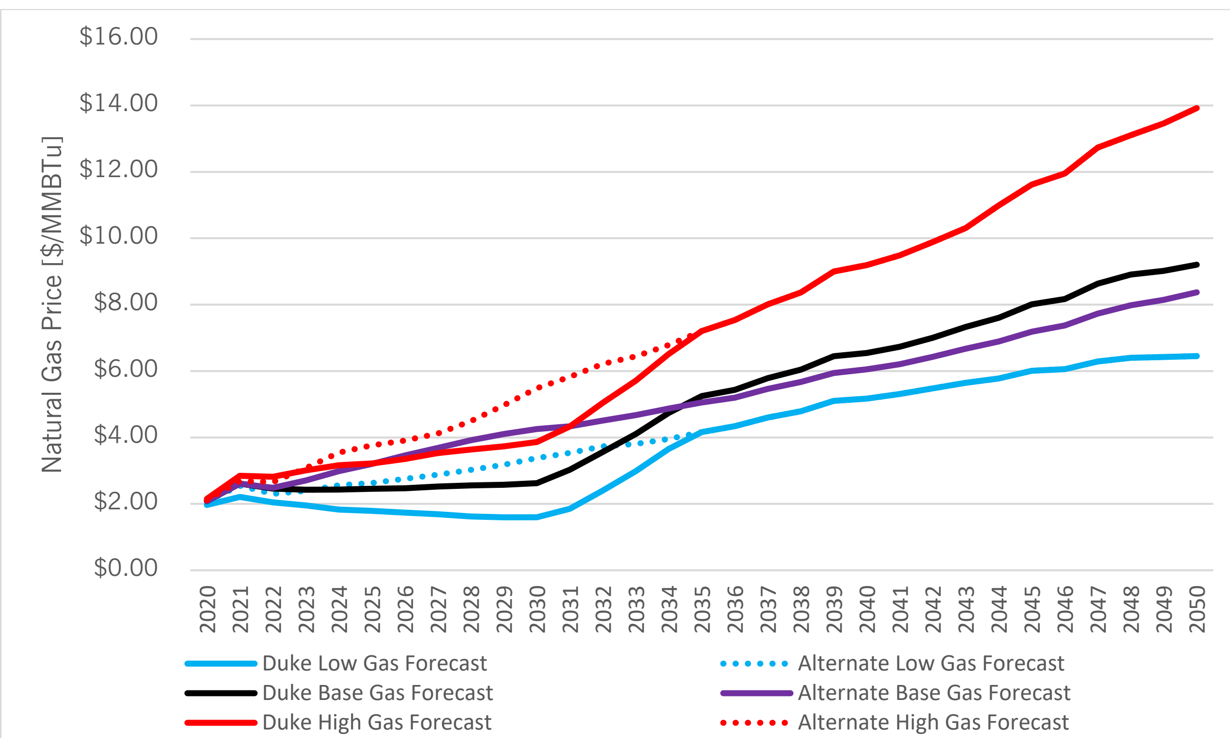
Additionally, consistent with recent deployments of solar resources in the Carolinas, the Company updated the original assumption that future solar would be a combination of fixed tilt and single axis tracking technologies, to an assumption that 100% of future solar resources would be designed as single axis tracking facilities (Ordering paragraph 15). This modification increases the capacity factor and reliable capacity of solar resources at time of peak system demand of these resources.

## FUEL PRICES

Fuel price assumptions remain an important factor in developing portfolios and evaluating the robustness of portfolios over a range of possible futures. Along with the high, base, and low natural gas price forecasts utilized in the September 2020 IRP, the Company has also developed an alternative set of natural gas price forecasts in compliance with the Commission's Order. The alternate gas price forecasts assume 18 months of market price natural gas, followed by 18 months of transition from market to a fundamentals-based natural gas forecast, followed by full utilization of the fundamentals-based price forecast beginning at the start of year 4 in the IRP planning window (Ordering paragraph 10). The fundamentals-based forecast utilizes a blend of two long-term natural gas fundamentals-based forecasts, the U.S. Energy Information Administration's (EIA's) 2020 Annual Energy Outlook (AEO) Reference case forecast and the Company's base fundamental forecast. Portfolios (A2 and B2) were economically optimized using this alternate base natural gas forecast.

The high and low alternative natural gas price forecasts were developed using the same 18 months of market forecast with 18 months of transition before full reliance on fundamentals-based forecasts. The alternative high and low market forecasts use the same data used to develop the Company's high and low gas market forecasts as in the September 2020 IRP, but instead of using the $10^{th}$ and $90^{th}$ percentile probabilities to develop these curves, the alternative market forecasts use the $25^{th}$ and $75^{th}$ percentile probabilities, resulting in a narrower range of market price forecasts. The high and low fundamentals-based forecasts used for the alternative gas price forecasts are consistent with those the Company used in its high and low forecasts, except for an earlier transition to these forecasts as dictated by the ordered blending schedule (Ordering paragraph 10). A comparison of these forecast is shown in Figure 3-C below.

## FIGURE 3-C
## NATURAL GAS PRICE FORECASTS, NOMINAL $ PER MMBTU



The alternate high, base, and low natural gas forecasts were used in the portfolio scenario analysis, along with the Company's high base and low natural gas forecasts. All six of these forecasts were used in scenario analysis to evaluate how all portfolios would perform under varying natural gas price projections.

Consistent with the September 2020 IRP, the supplemental IRP analysis also includes a natural gas price sensitivity in which Portfolios B1 and B2 were reoptimized using both a high and low natural gas prices to evaluate how the selection of resources may change with these different price forecasts. The Company used the alternate high forecast (dotted red line) and the Company's low gas forecast (solid blue line) to develop these sensitivity expansion plans. These forecasts were selected as they represent the highest and lowest forecasts among the six natural gas price forecasts.

## CAPITAL COST SENSITIVITY ANALYSIS

As discussed in Section 2, for the supplemental IRP analysis, the Company included in its economically optimized portfolio development, the ability for the capacity expansion model to select a solar PPA priced at $38/MWh in addition to a solar unit priced at the Company's base cost of service for a solar unit.

The Company's supplemental IRP analysis also includes capital cost sensitivities, similar to those performed in the September 2020 IRP. The Company includes in the supplemental IRP analysis, a solar capital cost sensitivity where the selection of resources in the portfolio is reoptimized based on the cost of solar resources.

The Company's low solar cost sensitivity replaces the $38/MWh solar PPA with a $36/MWh solar PPA (Ordering paragraph 13). This low solar cost case commensurately reduces the Company's assumed capital cost solar by 5%. Conversely the high solar cost sensitivity replaces the $38/MWh Solar PPA with a $40/MWh Solar PPA (Ordering paragraph 13) and increases the Company's assumed capital cost solar by 5%.

These solar cost sensitivities, due to their ability to produce carbon free energy, were performed against all the economically optimized portfolios (Portfolios A1, A2, B1, and B2).

As discussed in the energy storage assumption section, the two sets of economically optimized portfolios selected batteries using different battery cost assumptions. However, when comparing the financial results of the portfolios, a consistent battery cost was used for all portfolios, regardless if the portfolio was optimized with the base or alternate battery costs. This consistency eliminates portfolio cost variability due to different technology cost assumptions.

Finally, the Company also performed a 25-year book life gas sensitivity consistent with the September 2020 IRP.

## TECHNOLOGY ADVANCEMENTS

Advancement in, and deployment of, generation technologies such as offshore wind and nuclear small modular reactors (SMR) in the SC Supplemental Portfolios is consistent with the September 2020 IRP. The September 2020 IRP provides more detailed information regarding technology advancement assumptions.

## ENERGY STORAGE

The forecasted amount of battery additions incorporated into all portfolios as model inputs is consistent with the original IRP filing. The September 2020 IRP provides more detailed information regarding the inclusion of energy storage.

With the exception of modifications to the battery storage cost forecasts, as described herein, the manner in which energy storage was incorporated into the SC Supplemental Portfolios is consistent with the September 2020 IRP.

## ECONOMICALLY OPTIMIZED PORTFOLIO DEVELOPMENT AND RESULTS

The supplemental IRP analysis developed two sets of "economically optimized portfolios," or least cost plans, meaning the future resource selection was economically optimized by a series of capacity expansion and production cost modeling to determine the most economic set of resources under two optimization assumptions. These optimization assumptions include both optimization with including a carbon policy and without a carbon policy, which is modeled as a price on carbon. The economically selected portfolios include two versions of planning assumptions:

## PORTFOLIOS A1 AND B1

- accounting for the **federal tax credit extension** for solar development
- **increasing the solar interconnection constraint of the system** from 500 MW/year, approximately the average the combined Companies have interconnected in recent years, to 750 MW/year, which is consistent with the most the Companies have connected in a single year
- the energy and capacity value benefits of future solar are credited based on the trend of **future solar being exclusively single axis tracking** technology, as opposed to a mix of fixed tilt and single axis tracking
- inclusion of a **$38/MWh solar PPA as a selectable resource** in the economic optimization of the portfolio

## Portfolios A2 and B2

- include the same **input assumptions changes in Portfolios A1 and B1**
- use of the **alternate natural gas price forecast** using 18 months of market prices before transitioning across 18 months to a fundamental forecast
- optimize battery selection using the **NREL ATB Advanced ("Low") Battery Storage Cost** Forecast

The September 2020 IRP provides more detailed information regarding base case portfolio development.

The sections below discuss the portfolio optimization parameters and each of the resulting economically optimized portfolios.

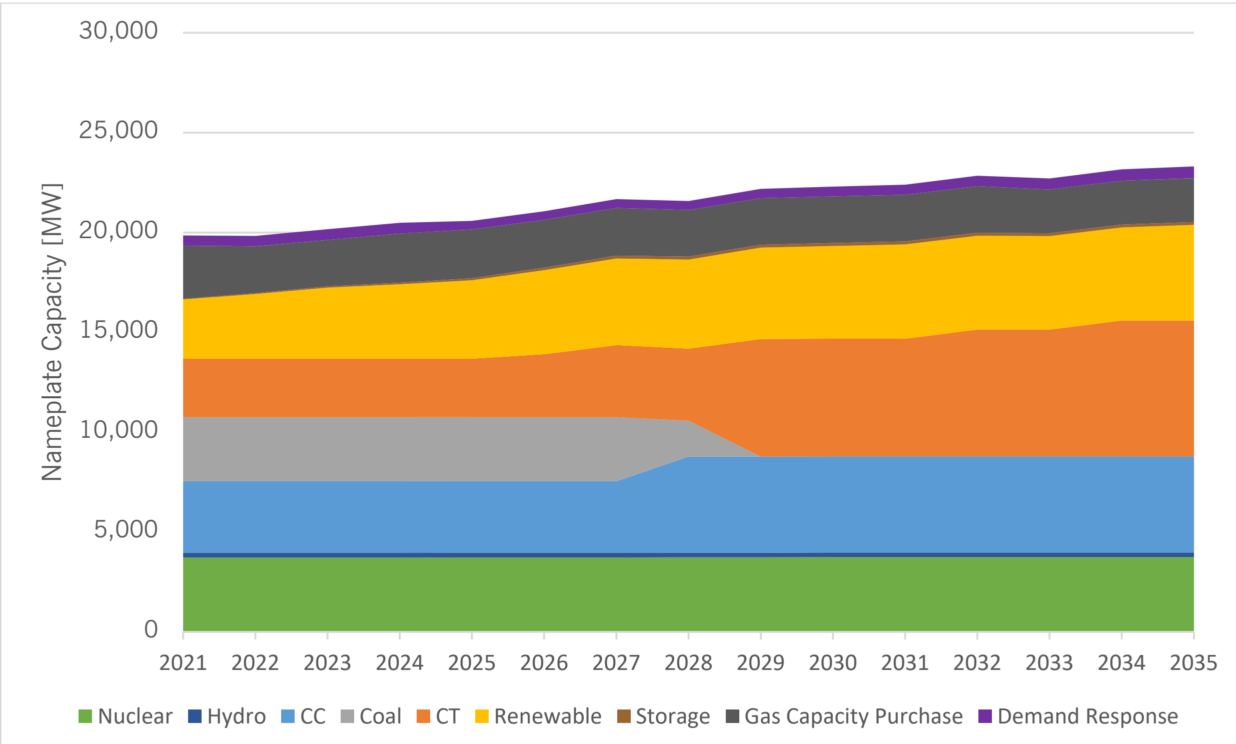
## PORTFOLIO A1: BASE CASE WITHOUT CARBON POLICY

Portfolio A1 was optimized in the same manner as Portfolio A from the September 2020 IRP. This portfolio uses the Company's base planning assumptions for fuel forecasts, load, EE, DSM, supply-side resources, and other operational inputs. There was no assumption on a price of carbon when developing this portfolio. This portfolio assumes that the optimization of resources is not influenced by a carbon constraint. The resources selected are based purely on delivering the portfolio that minimizes direct costs to customers while maintaining a reliable system meeting customers' demand and energy needs under these assumptions.

## PORTFOLIO AND RESULTS DISCUSSION

Portfolio A1 largely selects new natural gas generation to replace retiring coal generation. This portfolio adds approximately 5,350 MW of gas capacity to replace the retiring 3,200 MW of coal capacity and meet load growth. Even with the replacement of expiring contracts with in-kind replacement contracts, DEP still has capacity needs in starting in 2026, with the retirement of the Weatherspoon and Blewett CTs, a common assumption across all portfolios evaluated. However, most of this natural gas capacity is low capacity factor, peaking resources, with only one natural gas combined cycle added to the portfolio in 2028. Without a price on carbon emissions, the system relies on energy from the remaining coal units, to deliver the least cost energy to customers. In this portfolio, economically selected \$38/MWh solar PPA resource is added starting in 2034, bringing total solar on the DEP system to 5,250 MW by the end of the IRP planning horizon. Without additional economic support from either a carbon price or other supporting energy policy, neither solar at the Company's assumed capital cost nor \$38/MWh PPA Solar was economic in the first half of the planning horizon. Through the battery optimization of this portfolio, it was found that batteries were not economic within the IRP planning horizon.

## FIGURE 3-D
## DEP CAPACITY CHART - PORTFOLIO A1: BASE CASE WITHOUT CARBON POLICY



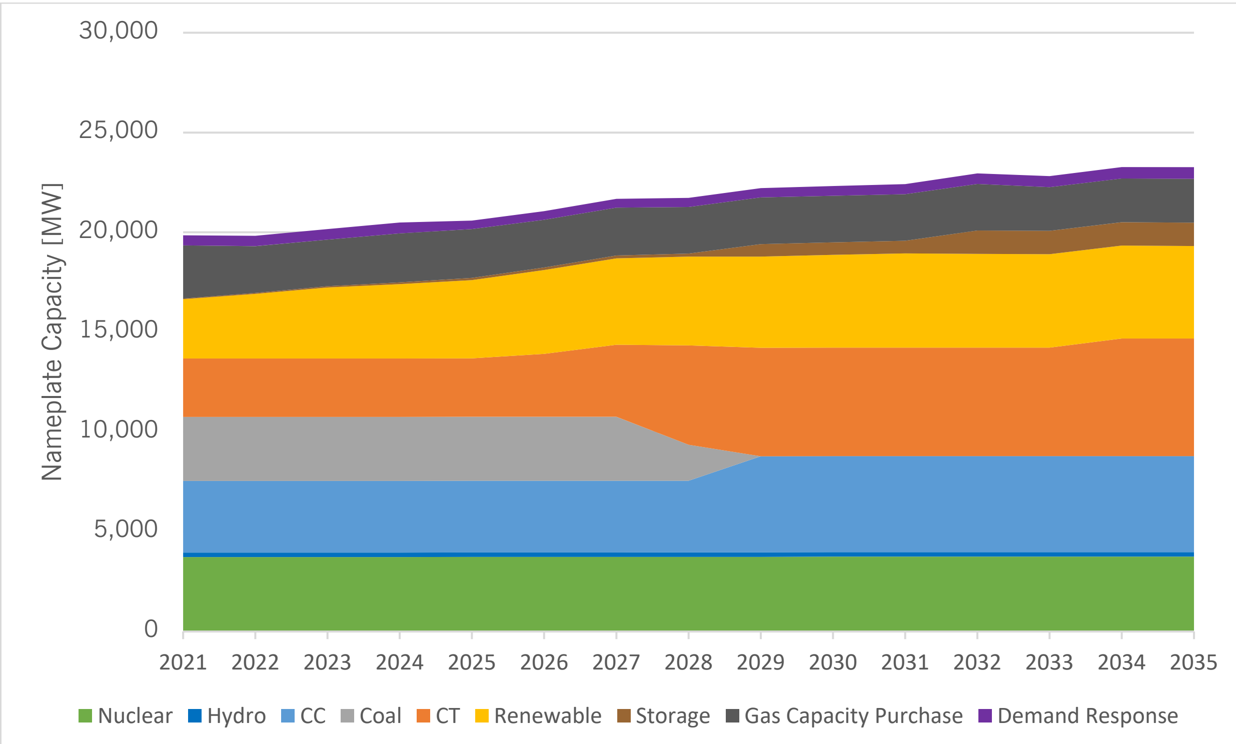

## PORTFOLIO A2: ALTERNATE GAS AND BATTERY COSTS WITHOUT CARBON POLICY

Portfolio A2, was optimized in the same manner as Portfolio A1, with exception of the use of the alternate gas price forecast and battery capital cost projections, as described earlier. This portfolio uses the Company's base planning assumptions for the remaining input assumptions, including load, EE, DSM, supply-side resources, and other operational inputs. Similar to Portfolio A1, there was no assumption of a price on carbon when developing this portfolio. This portfolio assumes that the optimization of resources is not influenced by a carbon constraint. The resources selected are based purely on delivering the portfolio that minimizes direct costs to customers while maintaining a reliable system meeting customers' demand and energy needs under these assumptions.

## PORTFOLIO AND RESULTS DISCUSSION

Portfolio A2 largely selects new natural gas generation to replace retiring coal generation, consistent with Portfolio A1. This portfolio adds the approximately 4,400 MW of gas capacity to replace the retiring 3,200 MW of coal capacity and meet load growth. The decrease in gas capacity is attributed to the economic replacement of peaking gas resources with utility scale batteries. The 1,000 MW of economical batteries replace approximately 900 MW of peaking gas capacity compared to Portfolio A1. These replacements were driven by the alternative battery cost used in the development of this portfolio. Even with the replacement of expiring contracts with in-kind replacement contracts, DEP still has capacity needs starting in 2026, with the retirement of the Weatherspoon and Blewett CTs, a common assumption across all portfolios evaluated. However, most of this natural gas capacity is low capacity factor, peaking resources, with only one natural gas combined cycle added to the portfolio in 2035. Without a price on carbon emissions, the system relies on energy from the remaining coal units to deliver the least cost energy to customers. For Portfolio A2, the model does not economically select either $38/MWh PPA solar or solar at the Company's assumed capital cost. Despite the lack of economically selected solar, this portfolio still results in an increase of 4,950 MW of solar to the DEP system by the end of the IRP planning horizon. Without additional economic support from either a carbon price or other supporting energy policy, none of the economically selectable solar options are selected in the portfolio in the planning horizon.

## FIGURE 3-E
## DEP CAPACITY CHART – PORTFOLIO A2: ALTERNATE GAS AND BATTERY COST WITHOUT CARBON POLICY




## PORTFOLIO B1: BASE CASE PLANNING WITH CARBON POLICY

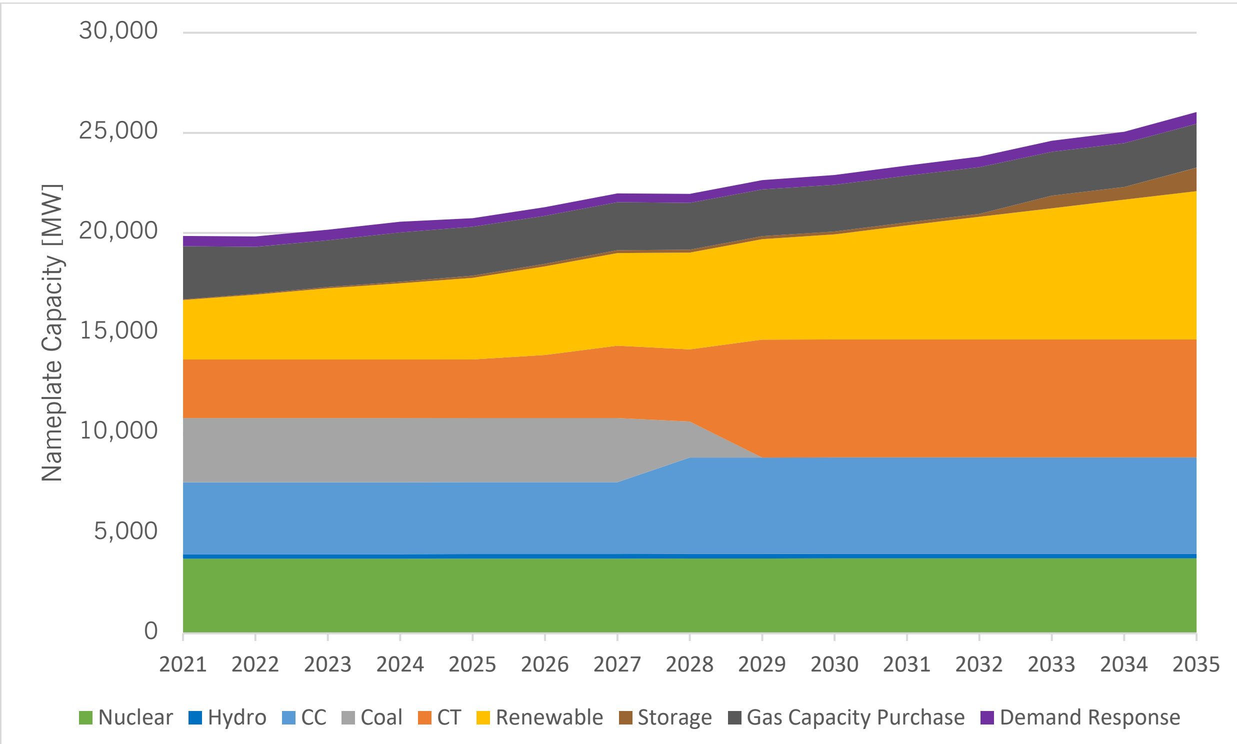
Portfolio B1 was optimized in the same manner as Portfolio B from the September 2020 IRP. This portfolio uses the Company's base planning assumptions for fuel forecasts, load, EE, DSM, supply-side resources and other operational inputs, the same assumptions used to economically optimize Portfolio A1. However, this portfolio was optimized with the assumption of a price of carbon when economically selecting the resources for the portfolio. This portfolio assumes that the optimization of resources is driven to reduce carbon emissions due to a price on carbon emissions while delivering the portfolio that most minimizes direct costs to customers while maintaining a reliable system to meet customers' demand and energy needs.

## PORTFOLIO AND RESULTS DISCUSSION

Portfolio B1, developed under the assumption of a future carbon policy, results in a more diverse set of resource additions than its No Carbon Policy counterpart, Portfolio A1. This portfolio adds approximately 900 MW less natural gas generation by 2035 compared to Portfolio A1, and instead adds approximately 2,300 MW of economically selected solar and solar plus storage and 900 MW of onshore Carolinas wind to meet energy and capacity needs created by retiring coal. With the introduction of the price on carbon, the portfolio begins selecting the $38/MWh solar PPA resource by the start of 2024, accelerating the incorporation of additional model-selected solar from 2034 in Portfolio A1. The model maxes out the economic selection of the $38/MWh solar PPA resource starting in 2024 and in every year through the remainder of the planning horizon in this portfolio. Solar at the Company's assumed capital cost is first selected by the start of 2031 by the start of 2034, solar plus storage resources at the Company's projected capital cost are economic and are selected by the model in addition to the amounts forced into the portfolio as part of the renewables forecast. The additions in this portfolio bring total solar on the DEP system to 7,250 MW by the end of the IRP planning horizon. The addition of the carbon policy assumption, in the form of a price on carbon, drives the model-selected addition of these non-carbon emitting resources in this supplemental IRP analysis. With the increased amount of intermittent resources in this portfolio, and the steep decline included in battery cost in the Company's base planning cost assumptions, the modeling found standalone battery additions to be economic in DEP.

FIGURE 3-F

DEP CAPACITY CHART – PORTFOLIO B1: BASE CASE PLANNING WITH CARBON POLICY



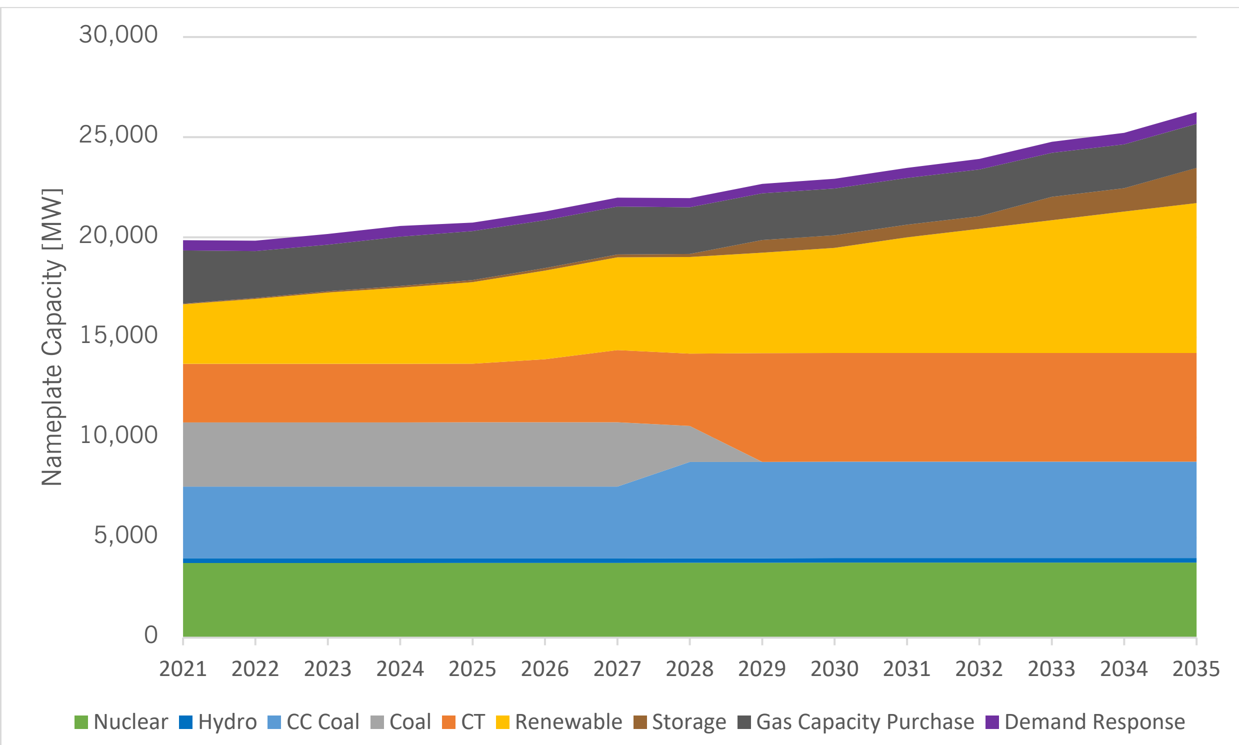

## PORTFOLIO B2: ALTERNATE GAS AND BATTERY COSTS WITH CARBON POLICY

Portfolio B2 was optimized in the same manner as Portfolio B1, with exception of the use of the alternate gas price forecast and battery capital cost projections, as introduced in the supplemental IRP analysis. This portfolio uses the Company's base planning assumptions for the remaining input assumptions, including load, EE, DSM, supply-side resources, and other operational inputs, the same as used to economically optimize Portfolio A2. However, this portfolio was optimized with the assumption of a price of carbon when economically selecting resources.

## PORTFOLIO AND RESULTS DISCUSSION

Portfolio B2, developed under the assumption of future carbon policy, results in a more diverse set of resource additions than its No Carbon Policy counterpart, Portfolio A2. This portfolio adds approximately 450 MW less natural gas generation by 2035 compared to the No Carbon Policy portfolios, and instead adds approximately 2,400 MW of economically selected solar and solar plus storage and 900 MW of onshore Carolinas wind to meet energy and capacity need created by retiring coal. The additions in this portfolio bring total solar on the DEP system to 7,350 MW by the end of the IRP planning horizon. The addition of the carbon policy assumption, in the form of a price on carbon, drives the model-selected addition of these non-carbon emitting resources in this supplemental IRP analysis. Finally, this portfolio includes the alternate battery costs assumption as compared to Portfolio B1. Portfolio B2, shows additional battery deployment is economic in DEP with approximately 1,350 MW of peaking gas capacity replaced with 1,600 MW of battery energy storage capacity, driven by changing to alternate battery cost forecast in the optimization of this portfolio.

### FIGURE 3-G
### DEP CAPACITY CHART – PORTFOLIO B2: ALTERNATE GAS AND BATTERY COST WITH CARBON POLICY



## KEY OBSERVATIONS AND TAKEAWAYS FROM ECONOMICALLY OPTIMIZED PORTFOLIOS

The main driver of the differences between the economically optimized portfolios is the inclusion of a carbon price in Portfolios B1 and B2. With the carbon policy assumption, the use of the NREL low battery costs shows accelerated and increased adoption of battery energy storage in DEP. DEP with its already high amount of solar energy, and lack of pumped storage hydro that DEC has, can more cost-effectively replace peaking gas capacity with batteries. While these battery energy storage is selected, it is not selected until the second half of the planning horizon when battery prices have further declined in the NREL ATB low battery price forecast, further confirming to the need for price declines in this technology, even at a lower starting cost.

The selection of near-term resources for Portfolios B1 and B2 are very similar, only notably diverging in the second half of the IRP planning horizon. This divergence occurs when batteries replace natural gas in Portfolio B2 due to the use of the NREL ATB low battery cost forecast. Significantly, the change in the natural gas forecast in the optimization of the portfolios from A1 and B1 to A2 and B2, does not materially change the timing or type of resources selected. All four economically optimized portfolios continue to select one combined cycle natural gas unit in the late 2020s, which corresponds to the retirement of all of DEP's coal capacity.

The battery optimization results reinforce that the system finds some amount of battery storage to be economic, especially in portfolios with high levels of variable energy resources. However, the need is not without limits, even at low battery cost projections. As shown in Portfolio B2, as battery costs aggressively decline in the alternate battery price forecast and more variable energy resources are added to the system, the value of battery energy storage increases to a level that results in the economic selection of an approximately 600 MW of additional storage relative to portfolio B1. As the Company continues to evaluate other opportunities for battery energy storage beyond bulk system benefits such as capacity and energy arbitrage value, it is possible that these resources will provide more benefits to the system that could lead to earlier economic adoption than shown in these portfolios. While future utility scale battery storage systems have the potential to play a pivotal role in decarbonizing the energy system, natural gas continues to be the most economic option for quickly and reliably retiring over 3,200 MW of coal capacity in DEP.

Below in Table 3-B is a comparison of the economically optimized portfolios' capacity expansion results.

## TABLE 3-B
## ECONOMICALLY OPTIMIZED PORTOFLIOS - CAPACITY CHANGES WITHIN IRP PLANNING HORIZON

| PORTFOLIO | A1 | A2 | B1 | B2 |
|---|---|---|---|---|
| Retired Coal Capacity [MW] | 3,208 | 3,208 | 3,208 | 3,208 |
| Incremental Solar [MW]┼ | 2,300 | 2,000 | 4,325 | 4,400 |
| Incremental Onshore Wind [MW]┼ | 0 | 0 | 900 | 900 |
| Incremental Offshore Wind [MW] | 0 | 0 | 0 | 0 |
| Incremental SMR Capacity [MW] | 0 | 0 | 0 | 0 |
| Incremental Storage [MW]╪ | 217 | 1,238 | 1,349 | 1,904 |
| Incremental Gas [MW] | 5,337 | 4,423 | 4,423 | 3,966 |
| Total Contribution from Energy Efficiency and Demand Response Initiatives [MW]* | 832 | 832 | 832 | 832 |

┼ Combined forecasted and model-selected incremental additions by the end of 2035.

╪ Includes Standalone Storage and Storage at Solar plus Storage sites

* Contribution of EE/DR (including Integrated Volt-Var Control (IVVC) and Distribution System Demand Response (DSDR)) in 2035 to peak winter planning hour.

## ECONOMICALLY OPTIMIZED PORTFOLIO SENSITIVITY ANALYSIS RESULTS

The sensitivity analysis performed in the supplemental IRP analysis is similar to that conducted in the September 2020 IRP. In sensitivity analysis, a single input variable is changed in the economic optimization process to assess the impact on resource additions and timing, the cost of the portfolio and the impact on emissions.

## SENSITIVITY ANALYSIS OVERVIEW

Sensitivity analysis in the supplemental IRP analysis, consistent with the sensitivity analysis in the September 2020 IRP, consists of developing economically optimized portfolios by changing a single input variable and observing changes in the selection and timing of resources, cost of the plan, and impact on emissions. Each of the sensitivities are optimized twice, once in the Company's base planning assumptions (those included in the development of portfolios A1 and B1), then a second time with the substitution of the alternate gas price and battery price forecasts assumptions. Each of these economically optimized sensitivities is then compared back to the economically optimized base portfolio (Portfolios B1, B2, A1, and A2) to determine how impactful each input variable is.

All of the sensitivities are performed with the assumption of a carbon policy and compared back to the performance of B1 and B2. Additionally, the high and low solar cost sensitivities are also performed without the assumption of a carbon policy and compared back to Portfolios A1 and A2.

These sensitivities inform the Company and stakeholders on the potential risks and opportunities associated with the portfolios. Below in Table 3-C is a list of sensitivities run in the supplemental IRP analysis.

TABLE 3-C

ECONOMICALLY OPTIMIZED PORTFOLIO SENSITIVTY ANALYSIS MATRIX

| | | Portfolio Optimization Scenarios | | | |
|---|---|---|---|---|---|
| | | With $CO_2$ Price | | Without $CO_2$ Price | |
| | | Base Gas and Battery Cost | Alternate Gas and Battery Cost | Base Gas and Battery Cost | Alternate Gas and Battery Cost |
| Sensitivity Variable | High Load Forecast | ✓ | ✓ | | |
| | Low Load Forecast | ✓ | ✓ | | |
| | Alternate High Gas Forecast | ✓ | ✓ | | |
| | Base Low Gas Forecast | ✓ | ✓ | | |
| | High Renewables Forecast | ✓ | ✓ | | |
| | Low Renewables Forecast | ✓ | ✓ | | |
| | High Renewables Cost | ✓ | ✓ | ✓ | ✓ |
| | Low Renewables Cost | ✓ | ✓ | ✓ | ✓ |
| | High EE | ✓ | ✓ | | |
| | Low EE | ✓ | ✓ | | |
| | High DR | ✓ | ✓ | | |
| | Low DR | ✓ | ✓ | | |
| | Pumped Storage | ✓ | ✓ | | |
| | 25-year New Gas Asset | ✓ | ✓ | | |

## SENSITIVITY ANALYSIS RESULTS

Tables 3-D and 3-E presents an overview of the year resources were economically selected by the capacity expansion model in each of sensitivities. A green, upward pointing arrow indicates an earlier date in the planning horizon compared to the base IRP portfolio of the same optimization variables. A red, downward pointing arrow indicates that the first year the resource was added was delayed within the planning horizon compared to the base portfolios. A yellow, horizontal dash indicates the resource timing did not change in that particular sensitivity. A “#N/A” appears for portfolios when the resource was not selected in the base cases or in the sensitivity.

The tables below show the results for the sensitivity analysis. The tables are organized by "sensitivity variable", "sensitivity scenario", and "planning scenario." The sensitivity variable is the singular input assumption that is being changed in the sensitivity. The sensitivity scenario describes how that singular input assumption is being changed, either increased (high), decreased (low), or the inclusion of a resource or cost of a resources (included). Finally, the planning scenario describes what set of assumptions were used to economically optimize the development of the portfolio for that sensitivity. For example, the first sensitivity shown is High Load, in the Base gas and Battery Cost portfolio development scenario. This means in the Company's base portfolio development assumptions were used, with the exception of high load forecast. The portfolio was developed using this set of assumptions and then is compared back to the base, economically optimized portfolio, in the portfolio development scenario it was optimized in, in this example, B1 in base gas price forecast and battery costs.

## TABLE 3-D

## DEP SENSITIVITY ANALYSIS WITH CARBON POLICY – FIRST YEAR OF ECONOMIC SELECTION BY RESOURCE TYPE

| CARBON POLICY SENSITIVITIES | | | First Year of Economic Selection | | | | | |
|---|---|---|---|---|---|---|---|---|
| SENSITIVITY VARIABLE | SENSITIVITY SCENARIO | PLANNING SCENARIO | CC | CT | Standalone Solar at PPA Cost | Standalone Solar at Capital Cost | Solar Plus Storage | Wind |
| Base | B1 | Base Gas and Battery Cost | 2028 | 2026 | 2024 | 2031 | 2034 | 2031 |
| | B2 | Alternate Gas and Battery Cost | 2028 | 2026 | 2024 | 2031 | 2035 | 2031 |
| Load | High | Base Gas and Battery Costs | 2028 | 2026 | 2025 | 2032 | 2033 | 2032 |
| | Low | | 2029 | 2027 | 2025 | 2034 | #N/A | 2032 |
| | High | Alternate Gas and Battery Costs | 2028 | 2026 | 2024 | 2031 | 2034 | 2032 |
| | Low | | 2028 | 2027 | 2024 | 2035 | #N/A | 2033 |
| EE | High | Base Gas and Battery Costs | 2028 | 2026 | 2025 | 2032 | 2034 | 2031 |
| | Low | | 2028 | 2026 | 2025 | 2033 | 2035 | 2031 |
| | High | Alternate Gas and Battery Costs | 2028 | 2026 | 2024 | 2033 | #N/A | 2033 |
| | Low | | 2028 | 2026 | 2024 | 2032 | 2034 | 2031 |
| DR | High | Base Gas and Battery Costs | 2028 | 2026 | 2025 | 2032 | 2032 | 2031 |
| | Low | | 2028 | 2026 | 2025 | 2032 | 2034 | 2032 |
| | High | Alternate Gas and Battery Costs | 2028 | 2026 | 2024 | 2032 | #N/A | 2031 |
| | Low | | 2028 | 2026 | 2024 | 2032 | 2034 | 2031 |
| Fuel Price | High | Base Gas and Battery Costs | 2028 | 2026 | 2024 | 2025 | 2030 | 2028 |
| | Low | | 2029 | 2026 | 2027 | 2034 | 2033 | 2034 |
| | High | Alternate Gas and Battery Costs | 2028 | 2026 | 2024 | 2025 | 2030 | 2028 |
| | Low | | 2029 | 2026 | 2027 | 2034 | 2033 | 2034 |
| Renewables Forecast | High | Base Gas and Battery Costs | 2028 | 2026 | 2025 | 2034 | #N/A | 2032 |
| | Low | | 2028 | 2026 | 2027 | 2029 | 2030 | 2031 |
| | High | Alternate Gas and Battery Costs | 2028 | 2026 | 2023 | #N/A | #N/A | 2032 |
| | Low | | 2028 | 2026 | 2027 | 2029 | 2031 | 2031 |
| Solar Cost | High | Base Gas and Battery Costs | 2028 | 2026 | 2025 | 2033 | 2034 | 2031 |
| | Low | | 2028 | 2026 | 2024 | 2031 | 2034 | 2033 |
| | High | Alternate Gas and Battery Costs | 2028 | 2026 | 2024 | 2033 | #N/A | 2031 |
| | Low | | 2028 | 2026 | 2024 | 2031 | 2034 | 2032 |
| Pumped Storage | Included | Base Gas and Battery Costs | 2028 | 2026 | 2025 | 2032 | 2034 | 2032 |
| | Included | Alternate Gas and Battery Cost | 2028 | 2026 | 2024 | 2031 | 2035 | 2033 |
| 25-Year Gas | Included | Base Gas and Battery Costs | 2028 | 2026 | 2025 | 2032 | 2034 | 2032 |
| | Included | Alternate Gas and Battery Cost | 2028 | 2026 | 2024 | 2035 | 2035 | 2032 |

# TABLE 3-E

## DEP SENSITIVITY ANALYSIS WITHOUT CARBON POLICY – FIRST YEAR OF ECONOMIC SELECTION BY RESOURCE TYPE

| NO CARBON POLICY SENSITIVITIES | | | First Year of Economic Selection | | | | | |
|---|---|---|---|---|---|---|---|---|
| SENSITIVITY VARIABLE | SENSITIVITY SCENARIO | PLANNING SCENARIO | CC | CT | Standalone Solar at PPA Cost | Standalone Solar at Capital Cost | Solar Plus Storage | Wind |
| Base | A1 | Base Gas and Battery Cost | 2028 | 2026 | 2035 | #N/A | #N/A | #N/A |
| | A2 | Alternate Gas and Battery Cost | 2029 | 2026 | #N/A | #N/A | #N/A | #N/A |
| Solar Cost | High | Base Gas and Battery Costs | 2029 | 2026 | #N/A | #N/A | #N/A | #N/A |
| | Low | | 2029 | 2026 | 2033 | #N/A | #N/A | #N/A |
| | High | Alternate Gas and Battery Costs | 2029 | 2026 | #N/A | #N/A | #N/A | #N/A |
| | Low | | 2029 | 2026 | #N/A | #N/A | #N/A | #N/A |

Several observations on resource selection in sensitivity analysis are discussed below:

- **Timing of new natural gas generation –** The timing for the need of new natural gas generation does not change generally across most sensitivities. In cases where the timing does change, the resource is typically only shifted one year. New gas generation is not accelerated when demand is higher than the base (High Load and Low EE), as the portfolio already has capacity need in 2026.

- **Type of new natural gas generation –** CTs are selected as the first natural gas resource in portfolios A1, A2, B1, and B2 and in all sensitivities. The capacity need in 2026 is driven by the retirement of Blewet and Weatherspoon CTs, so a CT is a logical replacement. With the retirement of all of DEP's coal capacity in the late 2020s, the system selects at least one CC in every economically optimized portfolio and sensitivity. The retirement of DEP coal assets drives dispatchable and around-the-clock generation to be part of the replacement capacity for these units.

- **Solar Energy –** With most sensitivities optimized in a carbon price scenario, solar is consistently selected and selected early in the planning horizon. The cost of solar is generally not impactful to the timing of the selection of standalone solar. Solar at the $38/MWh PPA cost is consistently selected in the mid-2020s across the sensitivities. The selection of solar at the Company's assumed capital cost tends to be more responsive to the sensitivity's assumption, varying from not being selected or selected at the end of the planning horizon in the low fuel, low load, and high renewable forecast (where more solar is already forced into the portfolio) sensitivities, to being selected as early as 2025, in the high fuel price sensitivities.

- **Wind Energy –** The timing of onshore Carolinas wind selection appears to be fairly sensitive to the input assumption, however, the resource is never selected before 2028 and never selected in sensitivities without a carbon price. Additionally, the value of wind generally rises with increased levels of solar, as the two resources can at times complement each other, with solar producing energy during daylight hours and the wind generating relatively more in the evening hours.

Tables 3-F and 3-G show the total amount of a given resource added to the portfolio and the change in load and/or EE in each of the sensitivities. These tables use the same icons as the previous tables, and in this case the arrows indicate if the amount has increased (green, upward pointing), decreased (red, downward pointing), or stayed the same (yellow, horizontal dash). The data and resulting changes in these tables are compared to the economically optimized portfolios A1, A2, B1, and B2 in the scenarios in which they were optimized.

## TABLE 3-F
## DEP SENSITIVITY ANALYSIS WITH CARBON POLICY - EXPANSION PLAN RESULTS

| CARBON POLICY SENSITIVITIES | | | 2035 Winter Peak Impact | | | Incremental Capacity Additions | | | |
|---|---|---|---|---|---|---|---|---|---|
| SENSITIVITY VARIABLE | SENSITIVITY SCENARIO | PLANNING SCENARIO | Peak Demand | EE | DSM | Gas | Solar | Wind | Storage |
| Base | B1 | Base Gas and Battery Cost | 15,966 | 243 | 589 | 4,423 | 4,325 | 900 | 1,362 |
| | B2 | Alternate Gas and Battery Cost | 15,966 | 243 | 589 | 3,966 | 4,400 | 900 | 1,915 |
| Load | High | Base Gas and Battery Costs | 16,480 | 243 | 589 | 4,733 | 4,175 | 750 | 1,382 |
| | Low | | 15,176 | 243 | 589 | 3,509 | 3,875 | 750 | 1,242 |
| | High | Alternate Gas and Battery Costs | 16,480 | 243 | 589 | 4,423 | 4,400 | 600 | 1,855 |
| | Low | | 15,176 | 243 | 589 | 3,052 | 3,800 | 600 | 1,875 |
| EE | High | Base Gas and Battery Costs | 15,722 | 488 | 589 | 3,966 | 4,175 | 900 | 1,302 |
| | Low | | 16,027 | 183 | 589 | 4,276 | 4,025 | 900 | 1,302 |
| | High | Alternate Gas and Battery Costs | 15,722 | 488 | 589 | 3,819 | 4,100 | 600 | 1,835 |
| | Low | | 16,027 | 183 | 589 | 3,966 | 4,250 | 750 | 1,875 |
| DR | High | Base Gas and Battery Costs | 15,966 | 243 | 1,011 | 3,819 | 4,175 | 900 | 1,342 |
| | Low | | 15,966 | 243 | 468 | 4,423 | 4,175 | 750 | 1,342 |
| | High | Alternate Gas and Battery Costs | 15,966 | 243 | 1,011 | 3,509 | 4,250 | 900 | 1,835 |
| | Low | | 15,966 | 243 | 468 | 3,966 | 4,250 | 900 | 1,915 |
| Fuel Price | High | Base Gas and Battery Costs | 15,966 | 243 | 589 | 3,966 | 4,775 | 1,350 | 1,522 |
| | Low | | 15,966 | 243 | 589 | 4,423 | 3,800 | 450 | 1,302 |
| | High | Alternate Gas and Battery Costs | 15,966 | 243 | 589 | 3,509 | 4,775 | 1,350 | 2,115 |
| | Low | | 15,966 | 243 | 589 | 3,966 | 3,800 | 450 | 1,895 |
| Renewables Forecast | High | Base Gas and Battery Costs | 15,966 | 243 | 589 | 3,966 | 5,510 | 750 | 1,845 |
| | Low | | 15,966 | 243 | 589 | 4,423 | 3,450 | 900 | 1,296 |
| | High | Alternate Gas and Battery Costs | 15,966 | 243 | 589 | 3,509 | 5,435 | 750 | 2,437 |
| | Low | | 15,966 | 243 | 589 | 3,819 | 3,450 | 900 | 1,868 |
| Solar Cost | High | Base Gas and Battery Costs | 15,966 | 243 | 589 | 4,276 | 4,025 | 900 | 1,302 |
| | Low | | 15,966 | 243 | 589 | 4,423 | 4,325 | 600 | 1,362 |
| | High | Alternate Gas and Battery Costs | 15,966 | 243 | 589 | 3,966 | 4,100 | 900 | 1,835 |
| | Low | | 15,966 | 243 | 589 | 3,819 | 4,400 | 750 | 1,935 |
| Pumped Storage | Included | Base Gas and Battery Costs | 15,966 | 243 | 589 | 4,423 | 4,175 | 750 | 1,362 |
| | Included | Alternate Gas and Battery Cost | 15,966 | 243 | 589 | 3,966 | 4,400 | 600 | 1,915 |
| 25-Year Gas | Included | Base Gas and Battery Costs | 15,966 | 243 | 589 | 4,423 | 4,100 | 750 | 1,342 |
| | Included | Alternate Gas and Battery Cost | 15,966 | 243 | 589 | 3,966 | 3,800 | 750 | 1,895 |

## TABLE 3-G
## DEP SENSITIVITY ANALYSIS WITHOUT CARBON POLICY - EXPANSION PLAN RESULTS

| NO CARBON POLICY SENSITIVITIES | | | 2035 Winter Peak Impact | | | Incremental Capacity Additions | | | |
|---|---|---|---|---|---|---|---|---|---|
| SENSITIVITY VARIABLE | SENSITIVITY SCENARIO | PLANNING SCENARIO | Peak Demand | EE | DSM | Gas | Solar | Wind | Storage |
| Base | A1 | Base Gas and Battery Cost | 15,966 | 243 | 589 | 5,337 | 2,300 | 0 | 223 |
| | A2 | Alternate Gas and Battery Cost | 15,966 | 243 | 589 | 4,423 | 2,000 | 0 | 1,243 |
| Solar Cost | High | Base Gas and Battery Costs | 15,966 | 243 | 589 | 5,337 | 2,000 | 0 | 223 |
| | Low | | 15,966 | 243 | 589 | 5,337 | 2,525 | 0 | 223 |
| | High | Alternate Gas and Battery Costs | 15,966 | 243 | 589 | 4,423 | 2,000 | 0 | 1,243 |
| | Low | | 15,966 | 243 | 589 | 4,423 | 2,000 | 0 | 1,243 |

The following tables (Table 3-H through Table 3-L) provide greater detail on the impacts of each sensitivity performed, including impact to PVRR and $CO_2$ emissions by 2030 and 2035.

TABLE 3-H

DEP PVRR ANALYSIS OF SENSITIVITIES DEVELOPED WITH CARBON POLICY THROUGH 2050, EXCLUDING THE EXPLICIT COST OF CARBON, $ BILLIONS

| | B1 in Base Gas and Battery Cost | B2 in Alternate Gas and Battery Cost |
|---|---|---|
| With Carbon Policy Scenario | $35.1 | $35.2 |

| | PVRR | Delta from B1 in Base | Percent Change from B1 in Base | PVRR | Delta from B2 in Base | Percent Change from B2 in Base |
|---|---|---|---|---|---|---|
| High Load Forecast | $36.1 | $0.9 | 2.7% | $36.1 | $0.9 | 2.6% |
| Low Load Forecast | $33.0 | -$2.1 | -5.9% | $32.9 | -$2.4 | -6.7% |
| Alternate High Gas Forecast | $40.4 | $5.3 | 15.2% | $39.6 | $4.3 | 12.3% |
| Base Low Gas Forecast | $32.0 | -$3.1 | -8.9% | $31.2 | -$4.0 | -11.4% |
| High Renewables Forecast | $37.8 | $2.7 | 7.8% | $37.8 | $2.6 | 7.4% |
| Low Renewables Forecast | $34.9 | -$0.2 | -0.7% | $33.3 | -$2.0 | -5.6% |
| High Renewables Cost | $34.8 | -$0.3 | -0.8% | $35.1 | -$0.1 | -0.2% |
| Low Renewables Cost | $34.6 | -$0.5 | -1.5% | $34.7 | -$0.5 | -1.4% |
| High EE | $35.0 | -$0.2 | -0.4% | $34.8 | -$0.4 | -1.2% |
| Low EE | $33.6 | -$1.5 | -4.3% | $33.6 | -$1.6 | -4.6% |
| High DR | $35.0 | -$0.1 | -0.2% | $33.6 | -$1.6 | -4.5% |
| Low DR | $34.8 | -$0.3 | -0.8% | $34.9 | -$0.3 | -1.0% |
| Pumped Storage | $34.7 | -$0.4 | -1.0% | $34.9 | -$0.4 | -1.0% |
| 25-year New Gas Asset | $34.2 | -$1.0 | -2.7% | $35.0 | -$0.2 | -0.6% |

DUKE ENERGY PROGRESS

TABLE 3-I

DEP PVRR ANALYSIS OF SENSITIVITIES DEVELOPED WITH CARBON POLICY THROUGH 2050, INCLUDING THE EXPLICIT COST OF CARBON, $ BILLIONS

| | B1 in Base Gas and Battery Cost | B2 Alternate Gas and Battery Cost |
|---|---|---|
| With Carbon Policy Scenario | $42.4 | $42.3 |

| | PVRR | Delta from B1 in Base | Percent Change from B1 in Base | PVRR | Delta from B2 in Base | Percent Change from B2 in Base |
|---|---|---|---|---|---|---|
| High Load Forecast | $44.0 | $1.6 | 3.8% | $43.9 | $1.6 | 3.7% |
| Low Load Forecast | $39.9 | -$2.5 | -5.9% | $39.8 | -$2.5 | -6.0% |
| Alternate High Gas Forecast | $47.6 | $5.2 | 12.3% | $46.5 | $4.2 | 9.9% |
| Base Low Gas Forecast | $39.7 | -$2.7 | -6.4% | $38.9 | -$3.4 | -8.1% |
| High Renewables Forecast | $45.2 | $2.8 | 6.5% | $45.2 | $2.9 | 6.8% |
| Low Renewables Forecast | $42.4 | $0.0 | -0.1% | $41.6 | -$0.8 | -1.8% |
| High Renewables Cost | $42.6 | $0.2 | 0.4% | $42.2 | -$0.1 | -0.3% |
| Low Renewables Cost | $42.3 | -$0.1 | -0.3% | $42.4 | $0.1 | 0.2% |
| High EE | $42.5 | $0.1 | 0.3% | $42.6 | $0.2 | 0.5% |
| Low EE | $41.4 | -$1.0 | -2.4% | $41.4 | -$0.9 | -2.2% |
| High DR | $42.7 | $0.3 | 0.6% | $42.5 | $0.2 | 0.5% |
| Low DR | $42.5 | $0.1 | 0.2% | $42.5 | $0.2 | 0.4% |
| Pumped Storage | $42.6 | $0.1 | 0.3% | $42.5 | $0.2 | 0.4% |
| 25-year New Gas Asset | $41.9 | -$0.5 | -1.1% | $42.7 | $0.3 | 0.8% |

## TABLE 3-J
## DEP PVRR ANALYSIS OF SENSITIVITIES DEVELOPED WITHOUT CARBON POLICY THROUGH 2050, $ BILLIONS

| | A1 in Base Gas and Battery Cost | A2 in Alternate Gas and Battery Cost |
|---|---|---|
| Without Carbon Policy Scenario | $35.0 | $35.2 |

| | PVRR | Delta from A1 in Base | Percent Change from A1 in Base | PVRR | Delta from A2 in Base | Percent Change from A2 in Base |
|---|---|---|---|---|---|---|
| High Renewables Cost | $35.1 | $0.1 | 0.2% | $35.3 | $0.1 | 0.2% |
| Low Renewables Cost | $34.9 | -$0.1 | -0.4% | $35.1 | -$0.1 | -0.4% |

TABLE 3-K

SENSITIVITY ANALYSIS – COMBINED SYSTEM $CO_2$ REDUCTIONS BY 2030

| | Base Gas and Base $CO_2$ Price | Alternate Gas and Base $CO_2$ | Base Gas and No $CO_2$ Price | Alternate Gas and No $CO_2$ Price |
|---|---|---|---|---|
| Base Cases | 59.5% | 60.3% | 56.1% | 53.4% |
| | | | | |
| High Load Forecast | 59.3% | 59.8% | | |
| Low Load Forecast | 63.3% | 63.8% | | |
| Alternate High Gas Forecast | 57.6% | 58.3% | | |
| Base Low Gas Forecast | 59.4% | 60.0% | | |
| High Renewables Forecast | 61.2% | 61.2% | | |
| Low Renewables Forecast | 59.4% | 59.6% | | |
| High Renewables Cost | 61.2% | 62.2% | 55.9% | 53.2% |
| Low Renewables Cost | 59.8% | 61.9% | 56.3% | 53.8% |
| High EE | 60.1% | 62.2% | | |
| Low EE | 60.7% | 59.5% | | |
| High DR | 61.8% | 60.1% | | |
| Low DR | 59.6% | 60.1% | | |
| Pumped Storage | 61.6% | 62.1% | | |
| 25-year New Gas Asset | 61.3% | 60.3% | | |
| | | | | |
| Reduction Range | 5.7% | 5.5% | 0.4% | 0.6% |

## TABLE 3-L
## SENSITIVITY ANALYSIS – COMBINED SYSTEM $CO_2$ REDUCTIONS BY 2035

| | Base Gas and Base $CO_2$ Price | Alternate Gas and Base $CO_2$ | Base Gas and No $CO_2$ Price | Alternate Gas and No $CO_2$ Price |
|---|---|---|---|---|
| Base Cases | 63.7% | 64.8% | 53.0% | 54.5% |
| | | | | |
| High Load Forecast | 61.6% | 62.1% | | |
| Low Load Forecast | 67.1% | 67.9% | | |
| Alternate High Gas Forecast | 61.7% | 63.9% | | |
| Base Low Gas Forecast | 62.6% | 63.1% | | |
| High Renewables Forecast | 65.1% | 65.7% | | |
| Low Renewables Forecast | 62.7% | 63.5% | | |
| High Renewables Cost | 64.5% | 64.5% | 52.5% | 52.4% |
| Low Renewables Cost | 63.5% | 65.8% | 51.8% | 54.9% |
| High EE | 64.0% | 65.4% | | |
| Low EE | 64.3% | 63.7% | | |
| High DR | 65.4% | 62.3% | | |
| Low DR | 63.8% | 64.5% | | |
| Pumped Storage | 63.6% | 64.2% | | |
| 25-year New Gas Asset | 64.6% | 64.5% | | |
| | | | | |
| Reduction Range | 5.6% | 5.8% | 0.7% | 2.5% |

Several key takeaways from the sensitivity analysis include:

- Without a carbon policy, solar is not selected until near the end of the planning horizon when fuel prices increase to the point to make $38/MWh PPA solar economic.
- As expected, higher fuel prices, lower solar costs, and carbon policy drive increases in solar, solar plus storage and wind resources.
- Fuel cost sensitivities have a significant impact on the range of PVRR outcomes highlighting the importance of continued diversity in the resource mix to minimize these risks.

- High and low load do not significantly drastically impact the selection of solar and wind but drive changes to firm capacity additions from natural gas or energy storage to reliably meet peak demand.

- Higher EE and DR/DSM shows very modest $CO_2$ reductions over Portfolios B1 and B2, generally with cost increases to the system.

- Overall PVRRs tend to decrease when less resources are needed in the portfolio in such sensitivities as the low load, while a high renewables cost sensitivity increases costs, but may have additional carbon or diversity benefits.

- Importantly with these sensitivities, the actions presented in the September 2020 IRP Short-Term Action Plan were not dramatically impacted by the results of the sensitivity analysis. While some sensitivity runs may cause resource timing to be accelerated, none introduce a significant pivot to planning over the next five years. Small movements in resource adoption timing results in relatively small PVRR impacts compared to sensitivities that require additional resources or defer resources outside the IRP planning horizon. While changes that occur in the 2020s are more significant than changes that occur in the 2030s, the minor shifts in timing do not cause significant impact.

Other sensitivities investigating the value of pumped storage hydro (PSH) and a 25-year life for natural gas assets versus the base assumption of a 35-year life were also developed.

## PUMPED STORAGE HYDRO

As non-dispatchable renewable resources increase in number on the Carolinas system, longer duration energy storage will become critical to maintaining a reliable system. These sensitivities incorporate the addition of additional PSH capacity in DEC in 2035 to evaluate how long duration pumped storage expansion can benefit the combined system, especially with respect to balancing the levels of renewables as seen in Portfolios B1 and B2. These sensitivities show that when using the base renewables forecast including the base solar interconnection limit of 750 MW/year, the total cost of the portfolios increase. A scenario with higher renewable penetration and by increased transmission capability between the DEP and DEC would likely increase the value of PSH and lower the cost delta between the two portfolios, as the majority of the solar resources are currently situated in DEP. The Company believes that under certain climate goals and carbon reduction policies, incremental PSH would be a valuable addition to the fleet and plans to further evaluate this important SC resource in future IRPs.

### 25-YEAR NATURAL GAS ASSETS

A sensitivity examining a shorter asset recovery period for new natural gas units did not change the selection, timing, or type of resources in the portfolio demonstrating the cost effectiveness of these resources even under shortened asset lives. While changing the asset recovery period of a new unit does not increase the overall capital cost of the unit, it increases the annual amount customers must pay each for the asset, as the cost of the unit is collected over a shorter time frame. However, a shortening of the asset recovery period of new natural gas units would more quickly reduce the net book value of these assets for future customers. This trade off slightly increased near-term costs to offset long-term risk may further incentivizes the use of low cost natural gas technology to transition the fleet out of coal while maintaining the option for continuing to operate the unit, converting the technology to operate on carbon free fuels like hydrogen, or allowing for the eventual replacement of the resource. Again, this shortened recovery period sensitivity in the both economically optimized planning scenarios does not change the selection, type, or timing of additional gas resources selected in the model.

## 5. DEVELOPMENT OF ALTERNATIVE PORTFOLIO CONFIGURATIONS

While economically optimized portfolios provide insight into the comparison of portfolios optimized with and without carbon policy, alternative portfolios are designed to achieve specific outcomes, thereby meeting targets such as ceasing to burn coal in the Company's generation fleet and meeting aggressive carbon reductions goal. While each of these portfolios attempts to accomplish specific outcomes, a detailed analysis also helps quantify the following considerations:

- **Tradeoffs** of total costs of the implementation and operation of the pathway
- **Pace of change** of the generation fleet
- The average **residential monthly bill impact**
- Dependency on **technological development and deployment**
- Dependency on **policy** to enable the transition

This section highlights the additional portfolios analyzed in the supplemental IRP analysis and discusses some of the different development approaches for each of the portfolios. The discussion also includes the incorporation of the changes to base planning assumptions as adopted in the Company's base planning economically optimized portfolios, discussed earlier in this section and throughout the supplemental IRP analysis.

## ALTERNATIVE PLANNING CASE RESULTS

### PORTFOLIO C1: EARLIEST PRACTICABLE COAL RETIREMENTS

Consistent with the September 2020 IRP, the Company evaluated the potential factors that would restrict the Utility from retiring (or ceasing to burn coal at) the current coal fleet at their earliest practicable dates. To cease coal operations totaling over 3,200 MW in DEP at the earliest practicable date, this analysis suspends traditional "least cost" economic planning considerations, focusing on procurement and construction timelines for replacement capacity. The evaluation of these accelerations is often restricted by infrastructure to enable the replacements.

Portfolio C1 was revised from Portfolio C in the September 2020 IRP to incorporate the same input assumptions discussed above for Portfolios A1 and B1 (the extension of the federal ITC for solar development, increased interconnection limit from 500 MW to 750 MW per year for the combined Carolinas system, the assumption that all future solar will be of the single axis tracking technology, and the inclusion of $38/MWh solar PPA).

The September 2020 IRP provides more detailed information regarding the earliest practicable coal retirement dates.

### PORTFOLIO AND RESULTS DISCUSSION

Of all the portfolios, Portfolio C1 provides the most immediate carbon reductions while balancing customer affordability and minimizing the risk of over-dependence on emerging technologies over the planning horizon. Utilizing the earliest practicable retirement dates established in the September 2020 IRP, the selection of replacement resources includes prescribed dispatchable resources required to enable accelerated coal retirements. This portfolio also includes a significant level of new renewables along with EE and DR projections, consistent with the economically optimized portfolios and the earliest practicable coal retirement portfolio in the September 2020 IRP. Similar to each of the economically optimized portfolios, CT capacity is added to the portfolio in 2026 to meet the first capacity need in DEP. In the

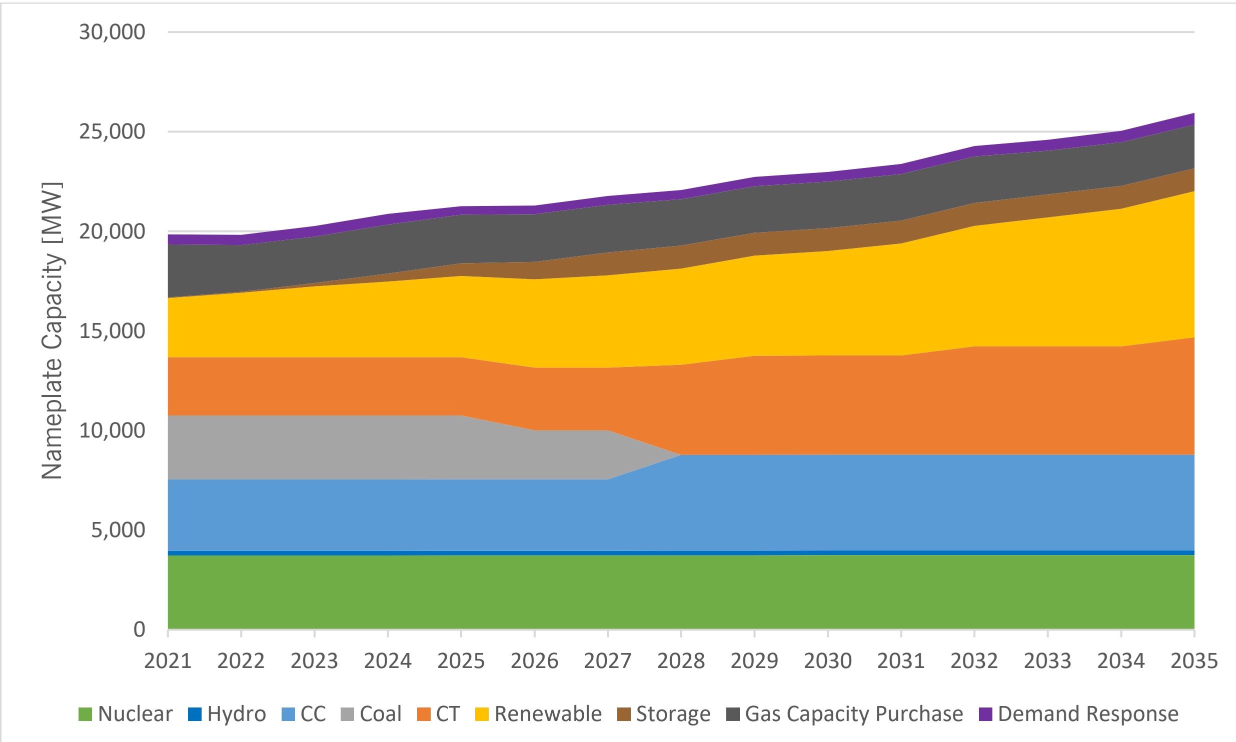
earliest practicable retirement date analysis, it was determined that the coal-fired Mayo Plant could be retired in 2026 with the deployment of utility scale battery storage more quickly than replacing with other traditional on- or offsite capacity. This battery storage deployment from 2023 through 2027 allows for the retirement of Mayo, by accelerating battery storage in the early 2030s from Portfolio B1. When all four units at the coal-fired Roxboro Station are retired in 2028, a combined cycle and CTs will replace these retiring fossil units on-site to avoid the transmission upgrades that would be required if the retiring capacity was replaced offsite. 2028 was determined to be the earliest that replacement capacity and transmission projects could be completed in DEP to enable the retirement of 2,400 MW at Roxboro Station. Additional deployment of battery storage or gas at an offsite location would likely require more time and therefore these retirement dates were selected. Overall, this portfolio eliminates coal generation from DEP by 2030, while aggressively adding 2,900 MW of solar by 2030. The aggressive coal retirements as well as the aggressive level of solar additions are made possible by utilizing existing infrastructure to effectively add efficient natural gas as an enabling transition resource to reliably replace retiring coal units while simultaneously improving dispatch flexibility to back up intermittent z
solar generation.

The solar additions in this case are slightly higher than those in B1. The portfolio also finds solar plus storage to be economic one year earlier compared to B1, at the start of 2033. Portfolio C1 adds 600 MW of onshore Carolinas wind, nearly the same amount and in the same time frame seen in Portfolio B1.

Achieving these coal retirements on this aggressive timeline and maintaining a reliable system would likely require supporting legislative and regulatory policy given the complexities in the siting, permitting, construction and regulatory approval required for such a large amount of resources in a short period of time.

FIGURE 3-H

## DEP CAPACITY CHART – PORTFOLIO C1: EARLIEST PRACTICABLE COAL RETIREMENTS




## PORTFOLIO C2: EARLIEST PRACTICABLE COAL RETIREMENTS WITH ALTERNATE GAS AND BATTERY PRICE FORECASTS

Along with evaluating Portfolio C1 as previously described, the Company developed an alternate Earliest Practicable Coal Retirements portfolio that also incorporated the additional assumptions utilized in Portfolios A2 and B2. Portfolio C2 used the same coal retirement dates and prescribed dispatchable replacement resources needed to accelerate coal unit retirements as Portfolio C1 but allows the partial optimization of the remainder of the portfolio. The partial optimization of the remainder of the portfolio uses all the assumptions from C1 with the exception of the alternate base gas price and battery price forecast assumptions used in the development of Portfolios A2 and B2.

As stated above, Portfolio C2 included the extension of the federal ITC for solar development, increased the interconnection limit from 500 MW to 750 MW per year for the combined Carolinas system, the assumption that all future solar will be of single-axis tracking technology, the inclusion of $38/MWh solar PPA, as well as the alternate gas price forecast and battery price projections used in the development of Portfolios A2 and B2.

## PORTFOLIO AND RESULTS DISCUSSION

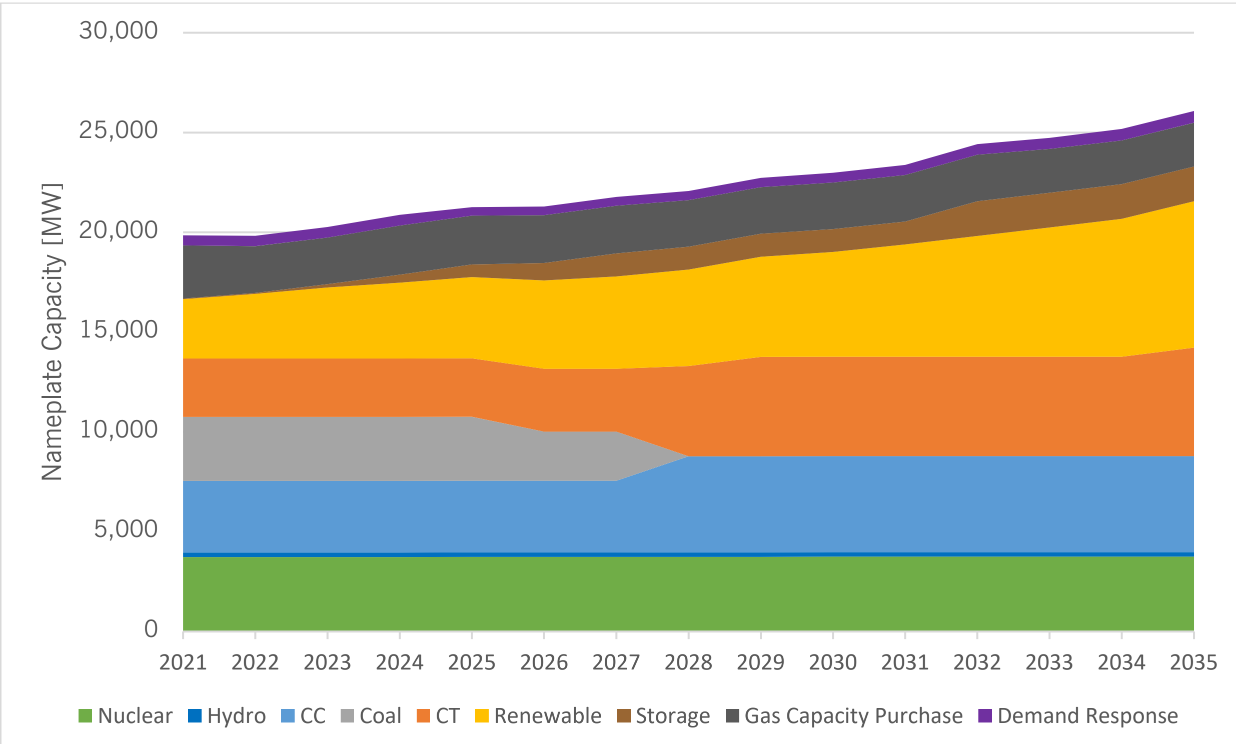
Portfolio C2 is consistent with Portfolio C1 in all capacity changes through 2030. The portfolio incorporates CT capacity to the portfolio in 2026 to meet the first capacity need in DEP. In the earliest practicable retirement date analysis, it was determined that Mayo could be retired in 2026 with the deployment of utility scale battery storage more quickly than replacing with other traditional on- or offsite capacity. This battery storage deployment from 2023 through 2027 allows for the retirement of the Mayo coal facility, by accelerating battery storage in the early 2030s from Portfolio B1. When all four units at Roxboro Station are retired in 2028, a combined cycle and CTs replace these retiring coal units on-site to avoid the transmission upgrades that would be required if the retiring capacity was replaced offsite. 2028 was determined to be the earliest that replacement capacity and transmission projects could be completed in DEP to enable the retirement of 2,400 MW at Roxboro Station. Additional deployment of battery storage or gas at an offsite location would likely require more time and therefore these retirement dates were selected. Overall, this portfolio eliminates coal generation from DEP by 2030, enabled primarily by utilizing existing infrastructure, and using natural gas combustion technology as an expedient transition out of coal.

The change in the natural gas price forecast in the partial optimization, and the use of the economical battery selections from Portfolio B2 in Portfolio C2, substitutes one additional block of CTs in the early 2030s and accelerated the economic selection of solar plus storage from 2035 to 2032. As with Portfolios A2 and B2, lower battery price assumptions result in a partial decrease in simple cycle turbines in the period 2030 and beyond in favor of battery storage. In the coming years leading up to 2030, future planning will be informed by actual industry experience with maturing battery storage technologies and the relative economics of both turbine and battery technologies. This will result in a convergence of what are now differing views on the future cost of energy storage.

As discussed for Portfolio C1, achieving these coal retirements, and maintaining a reliable system would likely require supporting legislative and regulatory policy given the complexities in the siting, permitting, construction and regulatory approval required for such a large amount of resources in a short period of time.

FIGURE 3-I

DEP CAPACITY CHART – PORTFOLIO C2: EARLIEST PRACTICABLE COAL RETIREMENTS WITH ALTERNATE GAS AND BATTERY PRICE FORECASTS




## PORTFOLIO D1: 70% $CO_2$ REDUCTION: OFFSHORE WIND

Similarly, compared to Portfolio D in the September 2020 IRP, Portfolio D1, 70% $CO_2$ Reduction: Offshore Wind, outlines a pathway to reduce $CO_2$ system emissions by 70% by 2030, from a 2005 baseline, by tapping into offshore wind resources off the coast of the Carolinas. This scenario explores the investment requirements, including the transmission, and the procurement, engineering, and construction challenges to bring this carbon-free resource into the portfolio and reduce the overall emissions of the system. The assumption of earliest practicable retirement dates underlies this portfolio to enable further reduction of carbon emissions by 2030.

Portfolio D1 was revised from Portfolio D in the September 2020 IRP to incorporate the same input assumptions discussed above for Portfolios A1 and B1 with the exception of the solar interconnection limit (the extension of the federal ITC for solar development, the assumption that all future solar will be of the single axis tracking technology, and the inclusion of $38/MWh solar PPA). This portfolio utilizes the high renewables forecast, with the interconnection constraint of solar increased to 900 MW per year across the combined Carolinas system, as was utilized in Portfolio D in the September 2020 IRP.

## PORTFOLIO AND RESULTS DISCUSSION

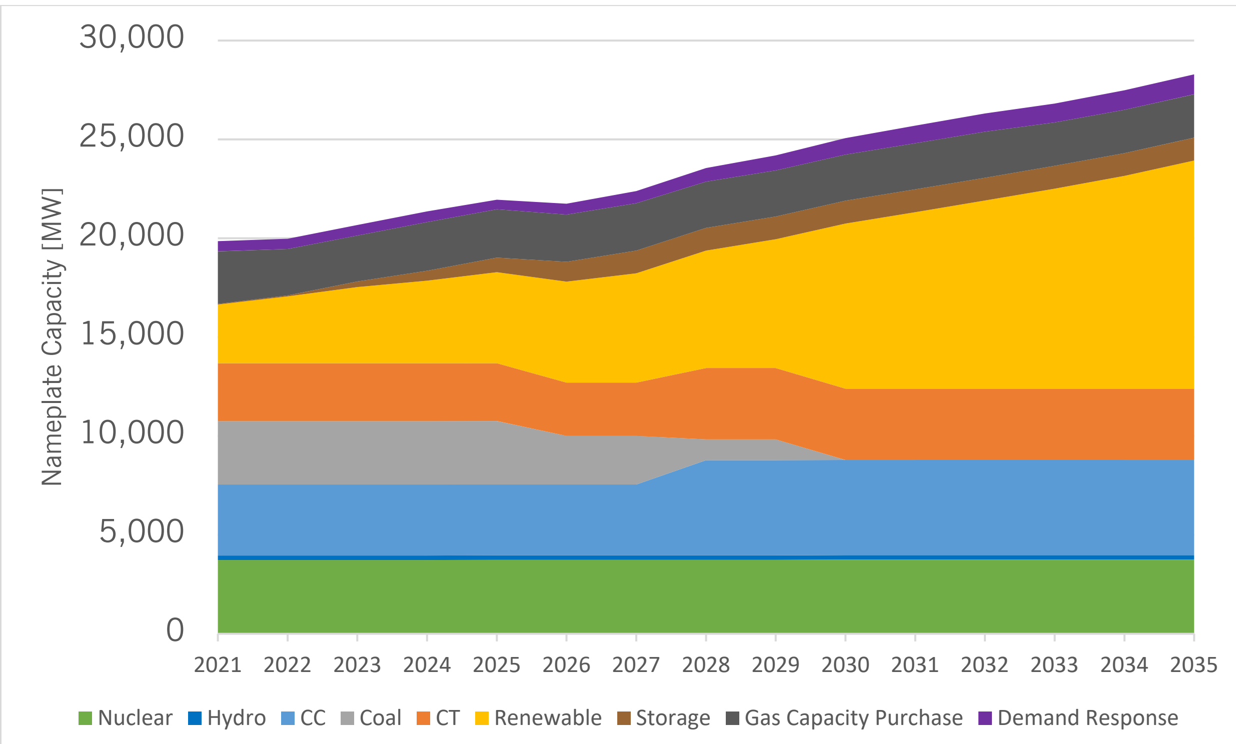
To help achieve 70% $CO_2$ reductions by 2030, Portfolio D1 incorporates the favorable assumptions of high renewables, energy efficiency, and demand response projections, to provide carbon-free capacity and energy to further reduce $CO_2$ emissions. This portfolio highlights that the accelerated retirement of carbon intense coal is not enough to reach the lofty 70% $CO_2$ reduction goals. Access to a more diverse supply of carbon-free energy is required to drive the additional gains in carbon reduction. As with the Portfolio C1, gas generation will be required to enable the expedited retirement of coal and provide system flexibility to accommodate a more intermittent resource mix while maintaining reliability and further reducing carbon emissions of the system.

This portfolio assumes that 1,200 MW of offshore wind are incorporated into the DEP service territory by 2030. To maintain enough capacity reserves before this offshore wind capacity can be constructed and connected to the system, the retirements of Roxboro units 1 and 2 are delayed two years from the earliest practicable retirement dates to 2030. Due to the geographical location of the offshore wind resource, significant transmission infrastructure would be required to deliver this energy to the DEP load centers and across the service territory. While offshore wind can provide bulk carbon-free energy, it does not provide one-for-one reliability equivalency. As an example, offshore wind was assumed to provide slightly more than 50% of its nameplate capacity towards meeting DEP's winter peak demand. Furthermore, as an intermittent resource, the remainder of the system will have to respond to intermittency in output from the offshore wind farm. While offshore wind capacity helps meet DEP's energy needs, the Company still requires additional gas generation to accelerate coal retirements and reliably meet growing customer load in the Company's service territory.

Utilizing the high renewables forecast, the increased solar interconnection of 900 MW/year for the combined Carolinas system, the introduction of less expensive solar resources and the $38/MWH solar PPA and extension of the federal ITC for solar development, this portfolio reaches over 9,600 MW of total solar on the DEP system by the end of the planning horizon. Additionally, this portfolio incorporates a total of over 2,900 MW of onshore and offshore wind resources while adding nearly 2,000 MW of storage capacity at solar plus storage sites and as standalone grid-tied battery energy storage.

While this portfolio achieves its intended outcome of 70% $CO_2$ reductions by 2030, it would require accelerated technological deployment, transmission permitting and construction, and supportive policy to enable this portfolio. While offshore wind is not necessarily a new technology, deployment in the U.S. at large scale is yet to be demonstrated. The cost of the resource and moving the energy from the Carolinas coast to the load in the central part of the state will present implementation challenges. These challenges can be mitigated with effective political and regulatory support and policy.

## FIGURE 3-J
## DEP CAPACITY CHART – PORTFOLIO D1: 70% $CO_2$ REDUCTION: OFFSHORE WIND




## PORTFOLIO E1: 70% $CO_2$ REDUCTION: NUCLEAR SMR

Similarly, compared to Portfolio E in the September 2020 IRP, Portfolio E1, 70% $CO_2$ Reduction: Nuclear Small Modular Reactor (SMR), outlines an illustrative pathway to reduce $CO_2$ system emissions by 70% by 2030 from a 2005 baseline by deploying advanced nuclear technologies by the end of this decade. This scenario explores the investment requirements, and procurement, engineering, and construction challenges to bring this carbon-free resource into the portfolio to reduce the overall emissions of the system. The assumption of earliest practicable retirement dates underlies this portfolio to enable further reduction of carbon emissions by 2030.

Portfolio E1 was revised from Portfolio E in the September 2020 IRP to incorporate the same input assumptions discussed above for Portfolios A1 and B1 with the exception of the solar interconnection limit (the extension of the federal ITC for solar development, the assumption that all future solar will be of the single axis tracking technology, and the inclusion of $38/MWh solar PPA). This portfolio utilizes the high renewables forecast and the higher interconnection constraint of solar of 900 MW/year across the combined Carolinas system, as was utilized in Portfolio E in the September 2020 IRP.

## PORTFOLIO AND RESULTS DISCUSSION

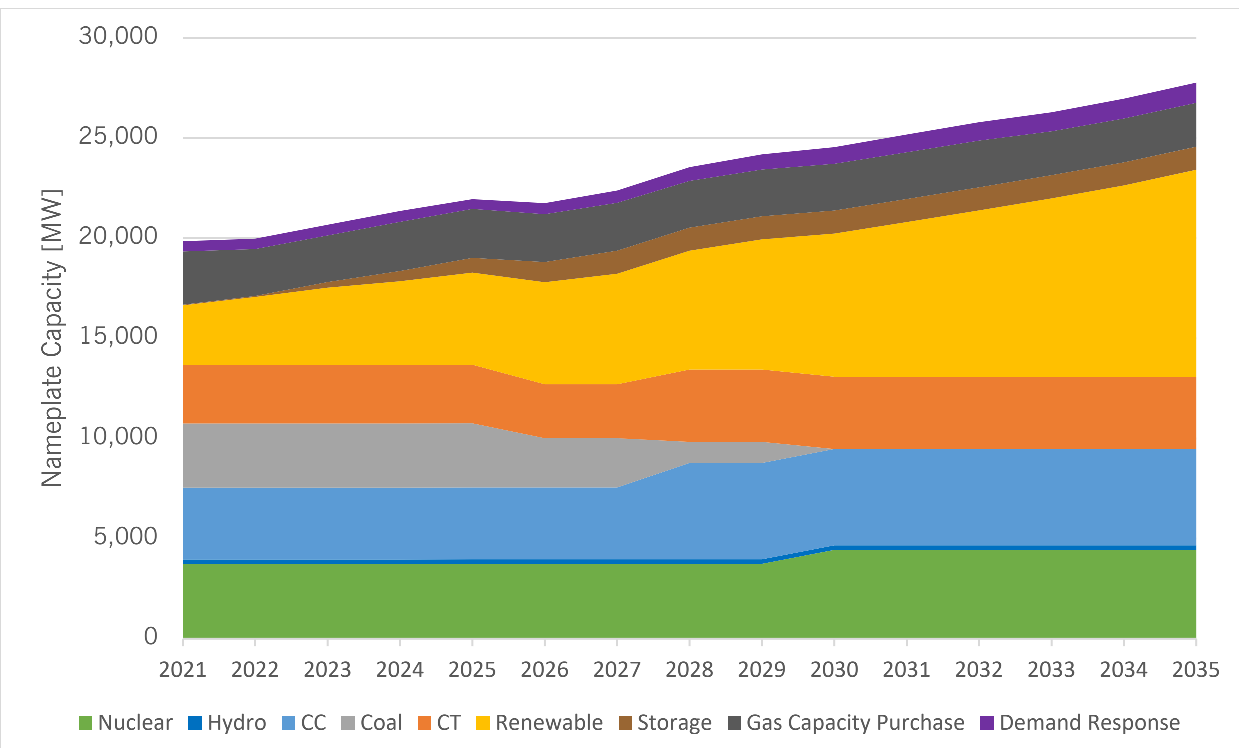
To help achieve 70% $CO_2$ reductions by 2030, Portfolio E1 assumes high renewables, energy efficiency, and demand response projections, to provide carbon-free capacity and energy to further reduce $CO_2$ emission. This portfolio highlights the carbon benefits of bringing advanced nuclear technologies into the Company's service territory and illustrates that the retirement of carbon intense coal resources alone is not enough to reach the 70% reduction goal. As with Portfolio D1, Portfolio D2 requires access to diverse sources of carbon-free energy and requires gas generation to enable the expedited retirement of coal and provide system flexibility and reliability while further reducing carbon emissions of the system.

This portfolio assumes the deployment of a 684 MW SMR nuclear plant in DEP by 2030. This technology presents an opportunity for a carbon-free resource that can adjust output up and down to follow trends in load, a characteristic that becomes increasingly valuable as variable energy resources continue to be added to the system. The addition of SMR capacity in this portfolio is relatively small compared to the nameplate capacity of the DEP system, but on an energy basis, these dispatchable resources provide a much greater annual output of carbon-free energy as compared to their intermittent renewable counterparts on a megawatt-for-megawatt basis.

In line with Portfolio D1, utilizing the high renewables forecast and the increased solar interconnection constraint of 900 MW/year for the combined Carolinas system, in addition to the introduction of less expensive solar resources, with the $38/MWH solar PPA and extension of the federal ITC for solar development, this portfolio reaches over 9,600 MW of total solar capacity on the DEP system by the end of the planning horizon. Additionally, this portfolio incorporates a total of over 1,700 MW of onshore and offshore wind resources, while adding a total of nearly 2,000 MW of storage capacity at solar plus storage sites and as standalone grid-tied battery energy storage.

While this portfolio achieves its intended outcome of 70% $CO_2$ reductions by 2030 and the system benefits from the flexible and carbon-free attributes of SMR, the ability to license, permit, and construct this emerging technology by 2030 presents a significant challenge. The first full-scale, commercial SMR project is slated for completion within the same time horizon as the resource needed in this scenario. To complete a project of this magnitude would require a high level of coordination between state and federal regulators, and even with that assumption, the timeline is still challenged based on the current licensing and construction timeline required to bring this technology to DEP. Nuclear reactors are not a new technology, but development and deployment of this design is yet to be demonstrated at scale. Uncertainty in the project cost and timeline is another factor that will need to be understood before embarking on a groundbreaking project of this magnitude.

### FIGURE 3-K
### DEP CAPACITY CHART – PORTFOLIO E1: 70% $CO_2$ REDUCTION: NUCLEAR SMR



## PORTFOLIO F1: NO NEW GAS GENERATION

As described in the September 2020 IRP, there is growing interest from environmental advocates and Environmental, Social, and Corporate Governance (ESG) investors to understand the impacts of no longer relying on natural gas as a bridge fuel to a net-zero carbon future. Portfolio F1, No New Gas Generation, explores a pathway, assuming the necessary technological and policy advancements, to bridge the gap between today and 2050 without building new gas generation. To evaluate the cost and operability of the system without gas as a transition fuel, this pathway assumes no new gas generation projects and meets the remaining capacity and energy needs of the DEP system with existing and emerging zero-carbon emitting resources, including solar, storage, onshore Carolinas wind and offshore wind at a large scale in the Carolinas.

Portfolio F1 was revised from Portfolio F in the September 2020 IRP to incorporate the same input assumptions discussed above for Portfolios A1 and B1 with the exception of solar interconnection limit (the extension of the federal ITC for solar development, the assumption that all future solar will be of the single axis tracking technology, and the inclusion of $38/MWh solar PPA). This portfolio uses the high renewables forecast, with the interconnection constraint of solar increased to 900 MW/year across the combined Carolinas system, as was used in Portfolio F in the September 2020 IRP.

## PORTFOLIO AND RESULTS DISCUSSION

In Portfolio F1, where economical gas generation additions are not added to the portfolio, and firm winter capacity remains the binding constraint, the system must rely on the existing portfolio until alternate dispatchable technologies, such as batteries, can be constructed on the system and emerging technologies become available. In order to allow technologies to reach maturity and decline in price, the most economic coal retirement dates, utilized in the economically optimized portfolio, were utilized in this portfolio delaying coal retirement from the earliest practicable coal retirements schedule. This coal capacity, with a secure fuel source and ability to match generation output with demand, provides the requisite capacity until the emerging and nascent technologies can be implemented throughout the system at scale.

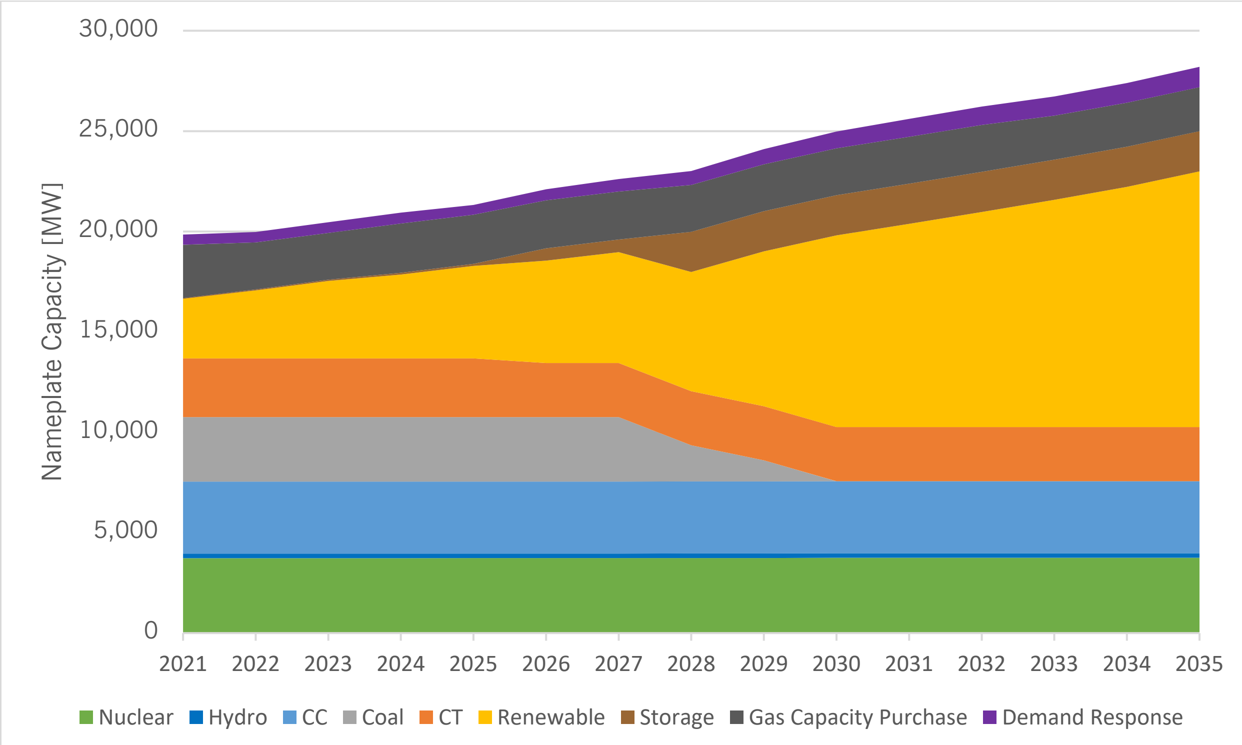
In DEP, even with leveraging high EE and DR while retaining coal capacity through its most economic retirement dates as used in the economically optimized portfolios, the utility must quickly begin procuring replacement resources. By 2030, to ensure the retirement of these units, the utility must deploy nearly

3,200 MW of 4-hr and 6-hr standalone batteries to the system. Additionally, DEP would need to procure 2,400 MW of offshore wind to diversify the resources to help meet energy and capacity needs by 2030. Finally, by the end of the IRP planning horizon, the Company would need to add another 1,000 MW of battery storage and incorporate over 1,600 MW of central Carolinas and high-quality midcontinent wind resources, to keep up with system energy and capacity need with declining capacity value of battery storage. Without the ability to wait for these technologies to mature, both operationally and economically, DEP would have to deploy very large-scale battery storage and offshore wind at large penetrations before they have proven their long-term effectiveness and economic maturity.

In line with Portfolios D1 and E1, utilizing the high renewables forecast, including the increased solar interconnection constraint relative to the economically optimized portfolios to 900 MW/year for the combined Carolinas system, in addition to the introduction of less expensive solar resources, with the $38/MWH solar PPA and extension of the federal ITC for solar development, this portfolio reaches over 9,600 MW of total solar on the DEP system by the end of the planning horizon. In sum, this portfolio incorporates a total of nearly 4,100 MW of onshore and offshore wind resources, while adding a total of nearly 5,000 MW of storage capacity at solar plus storage site and as standalone grid tied battery energy storage.

If the Company can implement high levels of EE and DR, and lean on existing resources to bridge the gap without relying on new gas generation, the system may be able to serve customers reliably, and with minimal cost impact, for a short period within the planning horizon. However, soon after the planning window, additional existing resources begin retiring, which will pose additional new challenges in meeting energy and capacity needs until more zero-emitting, load following resources can be deployed. Furthermore, this portfolio is underpinned with assumptions that in themselves may be difficult to achieve or control. Load growth of the system, especially with respect to electrification in this scenario, consistent with a future where the use of natural gas and other fossil fuels are restricted, could present accelerated cost and deployment challenges if capacity is needed earlier. Also, adding high levels of EE, DR, renewables, storage (including addition pumped storage hydro capacity) and emerging technologies cost-effectively to the system present their own significant challenges and risks. The resulting tradeoffs could include higher costs, slower $CO_2$ reductions and reliability challenges with the integration of new, less flexible technologies.

## FIGURE 3-L
## DEP CAPACITY CHART – PORTFOLIO F1: NO NEW GAS GENERATION




Below, Tables 3-M and 3-N illustrate the changes to system capacity in the IRP planning horizon for the Base Cases and Alternative Portfolios:

TABLE 3-M

BASE CASE AND ALTERNATIVE PORTFOLIO CAPACITY CHANGES WITHIN IRP PLANNING HORIZON

| PORTFOLIO | A1 | A2 | B1 | B2 | C1 | C2 | D1 | E1 | F1 |
|---|---|---|---|---|---|---|---|---|---|
| Reduction in Coal Generation Capacity [MW] | 3,208 | 3,208 | 3,208 | 3,208 | 3,208 | 3,208 | 3,208 | 3,208 | 3,208 |
| Incremental Solar [MW]┼ | 2,300 | 2,000 | 4,325 | 4,400 | 4,400 | 4,400 | 6,635 | 6,635 | 6,635 |
| Incremental Onshore Wind [MW]┼ | 0 | 0 | 900 | 900 | 750 | 750 | 1,622 | 1,622 | 1,622 |
| Incremental Offshore Wind [MW] | 0 | 0 | 0 | 0 | 0 | 0 | 1,292 | 92 | 2,492 |
| Incremental SMR Capacity [MW] | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 684 | 0 |
| Incremental Storage [MW]╪ | 217 | 1,238 | 1,349 | 1,904 | 1,370 | 1,846 | 1,916 | 1,916 | 4,901 |
| Incremental Gas [MW] | 5,337 | 4,423 | 4,423 | 3,966 | 4,423 | 3,966 | 2,138 | 2,138 | 0 |
| Total Contribution from Energy Efficiency and Demand Response Initiatives [MW]* | 832 | 832 | 832 | 832 | 832 | 832 | 1,499 | 1,499 | 1,499 |

┼Combined forecasted and model-selected incremental additions by the end of 2035.

╪Includes Standalone Storage, Storage at Solar plus Storage sites, and Pumped Storage Hydro.

*Contribution of EE/DR (including Integrated Volt-Var Control (IVVC) and Distribution System Demand Response (DSDR)) in 2035 to peak winter planning hour.

TABLE 3-N

COAL UNIT RETIREMENTS BY PORTFOLIO

| PORTFOLIO | A1 | A2 | B1 | B2 | C1 | C2 | D1 | E1 | F1 |
|---|---|---|---|---|---|---|---|---|---|
| Mayo 1 | 2029 | 2029 | 2029 | 2029 | 2026 | 2026 | 2026 | 2026 | 2029 |
| Roxboro 1 & 2 | 2029 | 2029 | 2029 | 2029 | 2028 | 2028 | 2030* | 2030* | 2030** |
| Roxboro 3 & 4 | 2028 | 2028 | 2028 | 2028 | 2028 | 2028 | 2028 | 2028 | 2028 |

*Delayed from Earliest Practicable Coal Retirement Dates for integration of offshore wind/SMR by 2030

**Delayed from Most Economic Coal Retirement Dates for integration of offshore wind by 2030

# 6. PORTFOLIO SCENARIO ANALYSIS

Portfolio scenario analysis looks at the performance of each portfolio over a broad range of scenarios and metrics to identify opportunities and risks with each. Each of the nine portfolios identified in the portfolio development analysis was evaluated in more detail with an hourly production cost model (PROSYM) under future fuel price and $CO_2$ price scenarios to determine the performance of each portfolio under varying fuel and carbon futures in terms of cost, carbon reduction, and reliability.

## SCENARIO ANALYSIS OVERVIEW

Scenario analysis in the supplemental IRP analysis, consistent with the scenario analysis in the September 2020 IRP, consists of running each of the IRP portfolios through a range of scenarios to observe how the portfolios perform with respect to cost, emissions, reliability, risk, and other factors.

A portfolio is the set of resources, both demand and supply side, available to be utilized to meet system loads. The production cost model will utilize a portfolio specified set of resources to minimize the cost of the system while meeting system load requirements. The production cost model may dispatch the resources in the portfolio differently among scenarios given the make-up of the resource portfolio and the costs to run those resources. As observed in portfolio development and sensitivity analysis, carbon policy and fuel prices are among the most impactful to the cost of operating the system and may impact cost as well as operations including projected emissions.

This supplemental IRP analysis consists of 18 scenarios differentiated by a carbon policy proxy (no $CO_2$ price, the base $CO_2$ price, or the high $CO_2$ price) and a natural gas price forecast (the Company's low, base and high natural gas price forecasts, and the alternate low base and high natural gas price forecasts), with all other assumptions remaining the same across all scenarios. The combinations of these three carbon price forecasts and six natural gas price forecasts make up the 18 scenarios in this analysis.

The matrix for the eighteen scenarios is illustrated in Table 3-O below.

### TABLE 3-O
### PORTFOLIO ANALYSIS MATRIX

| Natural Gas Price Scenarios | | Carbon Scenarios: No $CO_2$ Price | Carbon Scenarios: Base $CO_2$ Price | Carbon Scenarios: High $CO_2$ Price |
|---|---|---|---|---|
| Natural Gas Price Scenarios | Duke Low Fuel | ✓ | ✓ | ✓ |
| | Alternate Low Fuel | ✓ | ✓ | ✓ |
| | Duke Base Fuel | ✓ | ✓ | ✓ |
| | Alternate Base Fuel | ✓ | ✓ | ✓ |
| | Duke High Fuel | ✓ | ✓ | ✓ |
| | Alternate High Fuel | ✓ | ✓ | ✓ |

The nine portfolios were run through each of the 18 scenarios for 162 unique scenario analysis production cost model runs. The results of these runs are discussed throughout this section, focusing on various aspects of the performance of the portfolios.

## PORTFOLIO SCENARIO ANALYSIS RESULTS

## PRESENT VALUE OF REVENUE REQUIREMENT ANALYSIS

Present value of revenue requirement (PVRR) is a common Integrated Resource Planning metric used to quantify the relative costs across portfolios. This metric is calculated by assessing all future costs, which could vary across portfolios and scenarios, and discounting those future costs to customers to present day costs using the Company's discount rate. This metric captures the cost of adding new generation as well as system production costs. These production cost includes operating and maintaining the generation units, fuel costs, labor costs, and other costs to operate and maintain a reliable system. PVRR analysis is typically limited to costs associated with generating electricity to serve load, but starting in the September 2020 IRP, the Company included an estimate of the transmission costs associated with adding new generation and retiring existing units. Those generation-related transmission costs are included here as well. These costs may change from portfolio to portfolio and from scenario to scenario, based on the resources in the portfolio and their exposure to these operations and maintenance costs.

PROSYM, the hourly system production cost model, provides the production costs for each portfolio under the scenarios illustrated in Table 3-O. The model includes DEP's non-firm energy purchases and sales associated with the Joint Dispatch Agreement (JDA) with DEC, and as such, the model optimizes dispatch of both DEP and DEC and provides total system (DEP + DEC) production costs. The PROSYM results are separated to reflect system production costs that are solely attributable to DEP to account for the impacts of the JDA. The DEP-specific system production costs are then added to the DEP-specific capital costs to develop the total PVRR for each portfolio under the given fuel price and $CO_2$ price conditions. The results of this total cost analysis, excluding the explicit cost of the carbon tax to customers (as if the carbon policy were applied as a $CO_2$ mass cap where the cap is always met), is summarized in Table 3-P Figure 3-M below.

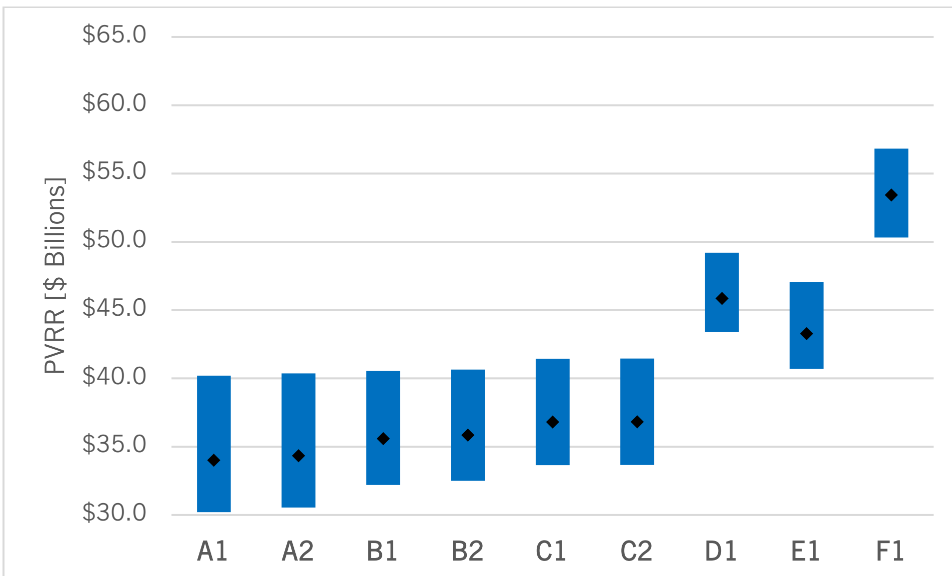
## TABLE 3-P
## DEP SCENARIO ANALYSIS TOTAL PVRR THROUGH 2050, EXCLUDING THE EXPLICIT COST OF CARBON, $ BILLIONS

| PORTFOLIO | A1 | A2 | B1 | B2 | C1 | C2 | D1 | E1 | F1 |
|---|---|---|---|---|---|---|---|---|---|
| High $CO_2$ / Duke High Fuel | $37.9 | $38.1 | $38.6 | $38.8 | $39.7 | $39.7 | $47.9 | $45.1 | $54.4 |
| High $CO_2$ / Alternate High Fuel | $38.8 | $39.1 | $39.5 | $39.7 | $40.5 | $40.5 | $48.5 | $45.8 | $55.1 |
| High $CO_2$ / Duke Base Fuel | $33.1 | $33.4 | $34.7 | $34.9 | $36.1 | $36.0 | $45.2 | $42.5 | $52.0 |
| High $CO_2$ / Alternate Base Fuel | $33.7 | $34.1 | $35.4 | $35.6 | $36.7 | $36.7 | $45.8 | $43.1 | $52.5 |
| High $CO_2$ / Duke Low Fuel | $30.2 | $30.5 | $32.2 | $32.5 | $33.7 | $33.7 | $43.4 | $40.7 | $50.3 |
| High $CO_2$ / Alternate Low Fuel | $31.6 | $32.0 | $33.6 | $33.8 | $34.9 | $35.0 | $44.5 | $41.8 | $51.4 |
| Base $CO_2$ / Duke High Fuel | $38.3 | $38.6 | $39.0 | $39.1 | $40.0 | $39.9 | $48.0 | $45.5 | $55.0 |
| Base $CO_2$ / Alternate High Fuel | $39.2 | $39.5 | $39.8 | $40.0 | $40.8 | $40.7 | $48.7 | $46.1 | $55.6 |
| Base $CO_2$ / Duke Base Fuel | $33.7 | $34.0 | $35.1 | $35.4 | $36.3 | $36.3 | $45.4 | $42.8 | $52.6 |
| Base $CO_2$ / Alternate Base Fuel | $34.3 | $34.6 | $35.8 | $36.1 | $36.9 | $37.0 | $46.0 | $43.4 | $53.2 |
| Base $CO_2$ / Duke Low Fuel | $30.7 | $31.1 | $32.6 | $32.9 | $33.9 | $33.9 | $43.6 | $41.0 | $51.0 |
| Base $CO_2$ / Alternate Low Fuel | $32.1 | $32.5 | $34.0 | $34.3 | $35.2 | $35.2 | $44.7 | $42.1 | $52.0 |
| No $CO_2$ / Duke High Fuel | $39.4 | $39.6 | $39.8 | $39.9 | $40.7 | $40.7 | $48.6 | $46.5 | $56.3 |
| No $CO_2$ / Alternate High Fuel | $40.2 | $40.4 | $40.5 | $40.6 | $41.4 | $41.5 | $49.2 | $47.1 | $56.8 |
| No $CO_2$ / Duke Base Fuel | $35.0 | $35.3 | $36.2 | $36.4 | $37.0 | $37.1 | $45.9 | $43.8 | $54.1 |
| No $CO_2$ / Alternate Base Fuel | $35.5 | $35.9 | $36.8 | $37.0 | $37.6 | $37.7 | $46.5 | $44.4 | $54.7 |
| No $CO_2$ / Duke Low Fuel | $32.1 | $32.5 | $33.7 | $34.0 | $34.6 | $34.7 | $44.1 | $42.1 | $52.6 |
| No $CO_2$ / Alternate Low Fuel | $33.5 | $33.9 | $35.1 | $35.3 | $35.9 | $36.0 | $45.2 | $43.1 | $53.6 |

| PORTFOLIO | A1 | A2 | B1 | B2 | C1 | C2 | D1 | E1 | F1 |
|---|---|---|---|---|---|---|---|---|---|
| Min | $30.2 | $30.5 | $32.2 | $32.5 | $33.7 | $33.7 | $43.4 | $40.7 | $50.3 |
| Median | $34.0 | $34.3 | $35.6 | $35.8 | $36.8 | $36.8 | $45.9 | $43.3 | $53.4 |
| Max | $40.2 | $40.4 | $40.5 | $40.6 | $41.4 | $41.5 | $49.2 | $47.1 | $56.8 |

FIGURE 3-M

DEP SCENARIO ANALYSIS TOTAL PVRR THROUGH 2050 RESULTS RANGE AND MEDIAN, EXCLUDING THE EXPLICIT COST OF CARBON, $ BILLIONS




Results tend to coalesce around the natural gas pricing scenarios rather than the underlying carbon price scenarios, pointing to greater risk associated with natural gas exposure than carbon emissions exposure, so long as the explicit cost of carbon is not passed on to customers. The portfolios most affected by varying natural gas prices are portfolios A1 and A2, which rely primarily on new gas generation to meet future energy needs. The PVRR for Portfolios D1, E1, and F1 are generally higher than the other portfolios in each scenario, but their cost sensitivity to fuel price is reduced. This is expected, as those plans shift away from natural gas resources and are naturally less sensitive to fluctuations in gas price. While the 70% $CO_2$ reduction and No New Gas Generation portfolios are less sensitive to gas prices, they are overall more expensive plans, as a result of the inclusion of more expensive resources with lower Effective Load Carrying Capabilities (ELCC) and energy output, as well as the cost of transmission needed to enable these resources.

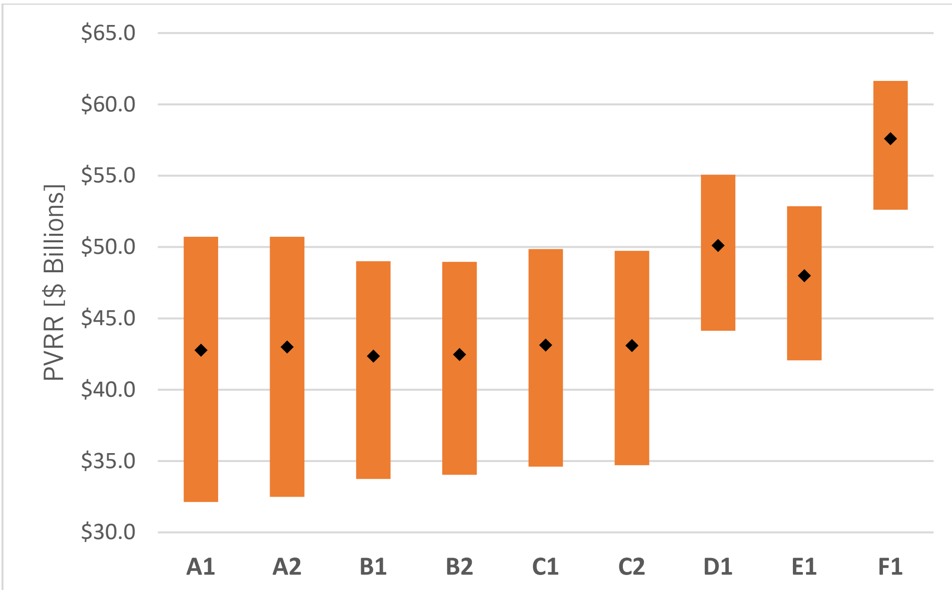
Shown summarized in Table 3-Q and Figure 3-N below are the results of the same total cost analysis as above, but now including the explicit cost of the carbon price to customers (as if the carbon policy were applied as a tax on carbon emissions).

### TABLE 3-Q
### DEP SCENARIO ANALYSIS TOTAL COST PVRR THROUGH 2050, INCLUDING THE EXPLICIT COST OF CARBON, $ BILLIONS

| PORTFOLIO | A1 | A2 | B1 | B2 | C1 | C2 | D1 | E1 | F1 |
|---|---|---|---|---|---|---|---|---|---|
| High $CO_2$ / Duke High Fuel | $49.9 | $49.9 | $48.3 | $48.2 | $49.1 | $48.9 | $54.4 | $52.2 | $61.0 |
| High $CO_2$ / Alternate High Fuel | $50.7 | $50.7 | $49.0 | $49.0 | $49.9 | $49.7 | $55.1 | $52.9 | $61.6 |
| High $CO_2$ / Duke Base Fuel | $45.6 | $45.8 | $44.7 | $44.8 | $45.4 | $45.4 | $51.8 | $49.6 | $59.0 |
| High $CO_2$ / Alternate Base Fuel | $46.1 | $46.3 | $45.3 | $45.4 | $46.0 | $45.9 | $52.3 | $50.2 | $59.5 |
| High $CO_2$ / Duke Low Fuel | $42.8 | $42.9 | $42.3 | $42.4 | $43.1 | $43.0 | $50.0 | $47.9 | $57.5 |
| High $CO_2$ / Alternate Low Fuel | $44.2 | $44.3 | $43.6 | $43.7 | $44.3 | $44.3 | $51.1 | $48.9 | $58.5 |
| Base $CO_2$ / Duke High Fuel | $47.1 | $47.2 | $46.0 | $46.0 | $46.9 | $46.8 | $52.9 | $50.7 | $59.9 |
| Base $CO_2$ / Alternate High Fuel | $47.9 | $48.0 | $46.8 | $46.8 | $47.6 | $47.6 | $53.5 | $51.3 | $60.5 |
| Base $CO_2$ / Duke Base Fuel | $42.8 | $43.0 | $42.4 | $42.5 | $43.2 | $43.2 | $50.2 | $48.1 | $57.7 |
| Base $CO_2$ / Alternate Base Fuel | $43.3 | $43.5 | $43.1 | $43.2 | $43.8 | $43.8 | $50.8 | $48.7 | $58.2 |
| Base $CO_2$ / Duke Low Fuel | $39.9 | $40.2 | $40.0 | $40.2 | $40.8 | $40.8 | $48.4 | $46.3 | $56.2 |
| Base $CO_2$ / Alternate Low Fuel | $41.3 | $41.6 | $41.4 | $41.5 | $42.1 | $42.1 | $49.5 | $47.4 | $57.2 |
| No $CO_2$ / Duke High Fuel | $39.4 | $39.6 | $39.8 | $39.9 | $40.7 | $40.7 | $48.6 | $46.5 | $56.3 |
| No $CO_2$ / Alternate High Fuel | $40.2 | $40.4 | $40.5 | $40.6 | $41.4 | $41.5 | $49.2 | $47.1 | $56.8 |
| No $CO_2$ / Duke Base Fuel | $35.0 | $35.3 | $36.2 | $36.4 | $37.0 | $37.1 | $45.9 | $43.8 | $54.1 |
| No $CO_2$ / Alternate Base Fuel | $35.5 | $35.9 | $36.8 | $37.0 | $37.6 | $37.7 | $46.5 | $44.4 | $54.7 |
| No $CO_2$ / Duke Low Fuel | $32.1 | $32.5 | $33.7 | $34.0 | $34.6 | $34.7 | $44.1 | $42.1 | $52.6 |
| No $CO_2$ / Alternate Low Fuel | $33.5 | $33.9 | $35.1 | $35.3 | $35.9 | $36.0 | $45.2 | $43.1 | $53.6 |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| Min | $32.1 | $32.5 | $33.7 | $34.0 | $34.6 | $34.7 | $44.1 | $42.1 | $52.6 |
| Median | $42.8 | $43.0 | $42.3 | $42.5 | $43.1 | $43.1 | $50.1 | $48.0 | $57.6 |
| Max | $50.7 | $50.7 | $49.0 | $49.0 | $49.9 | $49.7 | $55.1 | $52.9 | $61.6 |

## FIGURE 3-N
## DEP SCENARIO ANALYSIS TOTAL PVRR THROUGH 2050 RESULTS RANGE AND MEDIAN, INCLUDING THE EXPLICIT COST OF CARBON, $ BILLIONS




In contrast to the previous view, when the costs of carbon are included in the total cost of the plan, the range of PVRRs for each portfolio is increased. The economically optimized portfolios without carbon policy are again the portfolios that are most sensitive to fuel and carbon policies. While the lowest cost for the Portfolios B1, B2, C1, and C2 are higher than the lowest costs for A1 and A2, the highest costs for these portfolios are lower, due to less natural gas on the system, with its associated carbon emissions and cost based on the price of natural gas. Again, the highest carbon reduction portfolios, the 70% $CO_2$ reduction portfolios and the no new gas generation portfolio are less sensitive to the fuel and carbon variables, but are still the most expensive portfolios, even when the cost of carbon is included. The PVRR results for these portfolios are dependent on the structural and policy changes that enable carbon reductions, which will be discussed later in this section.

## PVRR MINIMAX REGRET ANALYSIS

The PVRR results can be difficult to interpret. To further assess the relative risk of the portfolios, the Company performed minimax regret analyses on the PVRR results, in compliance with the Commission's Order (Ordering paragraph 19). In this context, regret is defined as the amount by which the PVRR of a portfolio in a given scenario exceeds that of the lowest cost portfolio in that same scenario. In essence, the regret is the cost of selecting a portfolio that is suboptimal for a given scenario. The minimax regret analysis is intended to quantify the potential regret for each portfolio in each scenario, then to identify the portfolio that has the lowest maximum regret across all scenarios. It is a tool to understand the risks associated with each portfolio given the uncertainty in future fuel and carbon prices. Portfolios with a small amount of regret across a variety of pricing scenarios are robust in a variety of futures. Furthermore, a portfolio's mean regret represents the expected value of the regret for the portfolio assuming all scenarios are equally likely.

As a precautionary note, minimax regret analysis can be a useful tool for measuring relative risk of the pathways explored in the supplemental IRP analysis, but the analysis does lack context on its own. The analysis, when looking at mean regret, assumes all scenarios are equally likely. This means that a low gas price and no carbon policy future is just as likely as a high gas price, high $CO_2$ emissions price future in which with the cost of compliance is being directly passed onto customers. Both are possible, but it is hard to imagine either of those being as likely as a future with the Company's base gas forecast in combination with a more moderate policy around carbon emissions. Furthermore, the analysis assumes the portfolio is fixed and the Company would not react, adjust, and adapt to changing factors. If a carbon policy is enacted, it is likely the Company would adjust to a portfolio which is better suited to minimize cost to customers under that new regulatory structure. While minimax regret analysis can be part of the discussion for selecting the most reasonable and prudent means of meeting customer demand and energy needs, it should not be the only factor considered.

Below are the results of a series of minimax regret analyses in Tables 3-R through 3-U, showing the relative performance of each of the portfolios across the broad range of fuel and $CO_2$ price scenarios. The minimax regret analysis was performed both excluding and including the explicit cost of carbon in the total PVRR. The first analysis excludes the explicit cost of carbon. This distinction shows how these portfolios would perform under the assumed carbon policy if compliance was treated as a mass cap or shadow price in which the customer did not incur additional compliance costs. The second analysis includes this cost, as if the carbon policy was a direct price on every ton of carbon emitted and explicitly passed on to customers. The two versions of the analysis were then analyzed at the DEP level and at the Combined Carolinas (DEC and DEP Combined) level.

TABLE 3-R

DEP MIMIMAX REGRET ANALYSIS – EXCLUDING THE EXPLICIT COST OF $CO_2$ EMISSIONS, $ BILLIONS

| PORTFOLIO | A1 | A2 | B1 | B2 | C1 | C2 | D1 | E1 | F1 |
|---|---|---|---|---|---|---|---|---|---|
| Max Regret | $0.0 | $0.4 | $2.0 | $2.3 | $3.4 | $3.5 | $13.2 | $10.5 | $20.5 |
| Mean Regret | $0.0 | $0.3 | $1.3 | $1.5 | $2.4 | $2.4 | $11.2 | $8.7 | $18.6 |
| Regret Standard Deviation | $0.0 | $0.1 | $0.6 | $0.6 | $0.7 | $0.7 | $1.4 | $1.3 | $1.5 |

TABLE 3-S

DEP MIMIMAX REGRET ANALYSIS – INCLUDING THE EXPLICIT COST OF CO2 EMISSIONS, $ BILLIONS

| PORTFOLIO | A1 | A2 | B1 | B2 | C1 | C2 | D1 | E1 | F1 |
|---|---|---|---|---|---|---|---|---|---|
| Max Regret | $1.8 | $1.8 | $1.6 | $1.9 | $2.5 | $2.6 | $12.0 | $9.9 | $20.5 |
| Mean Regret | $0.5 | $0.7 | $0.4 | $0.5 | $1.2 | $1.2 | $8.4 | $6.3 | $15.9 |
| Regret Standard Deviation | $0.6 | $0.5 | $0.6 | $0.7 | $0.6 | $0.7 | $1.9 | $1.9 | $2.4 |

TABLE 3-T

CAROLINAS COMBINED MIMIMAX REGRET ANALYSIS – EXCLUDING THE EXPLICIT COST OF $CO_2$ EMISSIONS, $ BILLIONS

| PORTFOLIO | A1 | A2 | B1 | B2 | C1 | C2 | D1 | E1 | F1 |
|---|---|---|---|---|---|---|---|---|---|
| Max Regret | $0.0 | $0.4 | $3.6 | $4.5 | $5.3 | $5.9 | $23.4 | $18.4 | $30.7 |
| Mean Regret | $0.0 | $0.3 | $2.6 | $3.3 | $4.5 | $5.0 | $21.0 | $16.0 | $27.8 |
| Regret Standard Deviation | $0.0 | $0.1 | $0.9 | $1.0 | $0.6 | $0.7 | $1.9 | $1.9 | $2.5 |

## TABLE 3-U
## CAROLINAS COMBINED MIMIMAX REGRET ANALYSIS – INCLUDING THE EXPLICIT COST OF $CO_2$ EMISSIONS, $ BILLIONS

| PORTFOLIO | A1 | A2 | B1 | B2 | C1 | C2 | D1 | E1 | F1 |
|---|---|---|---|---|---|---|---|---|---|
| Max Regret | $3.0 | $3.0 | $3.6 | $4.5 | $5.3 | $5.9 | $23.4 | $18.4 | $30.7 |
| Mean Regret | $0.8 | $0.9 | $0.9 | $1.3 | $2.0 | $2.4 | $15.5 | $10.5 | $22.4 |
| Regret Standard Deviation | $1.0 | $0.9 | $1.3 | $1.6 | $2.0 | $2.2 | $4.6 | $4.6 | $4.5 |

Several observations on minimax regret analysis performed for the PVRR scenario analysis results are provided below:

- At the DEP level, and excluding the explicit cost of carbon, Portfolios A1 and A2 perform similarly, with A1 showing a slight advantage (lower maximum regret), likely due to fewer batteries. To reiterate, for consistency in interpreting the results these PVRRs use the Company's base battery costs across all portfolio, regardless how the portfolio was developed. The next two best performing portfolios are B1 and B2, showing a maximum of $2 billion and $2.3 billion, respectively. Portfolio B1's maximum regret is $0.3 billion less than B2, and it's mean regret, if all scenarios were equally as likely, is $0.2 billion less than Portfolio B2, representing a more robust performance across scenarios. Portfolios C1 and C2 follow closely behind the four economically optimized portfolios with a maximum regret of $3.4 and $3.5 billion respectively and a mean regret of $2.4 billion for each. This analysis shows the clear distinction between the first six portfolios and the latter three, which are more expensive and risk higher maximum regret.

- Still at the DEP level but including the explicit cost of $CO_2$ emissions being passed on to customers, the maximum regret of A1 and A2 increase from the analysis without explicit $CO_2$ cost, relative to the other portfolios. Portfolios B1 and B2 become the least risky with respect to PVRR in this minimax regret analysis, carrying the lowest mean and maximum regret across all scenarios.

- When the results were then analyzed at the Carolinas combined level, assessing the impact to DEP and DEC combined. This scenario, excluding the explicit price on $CO_2$ emissions, again shows that the economically optimized portfolios tend to perform the best, with Portfolios A1 and A2 leading the way, again with Portfolio A1 with the slight edge. Portfolio

B1 again out performs B2 and Portfolio C1 again out performs C2 both in maximum regret and mean regret.

- When the cost of $CO_2$ emissions is now assumed to be passed on to customers, again Portfolios A1 and A2 rise to be more in line with the other two economically optimized portfolios. This scenario, as seen in the DEP equivalent analysis, lowers the mean of B1 and B2, respectively without impacting their maximum regret value. In all of the High $CO_2$ price scenarios, and in the Base $CO_2$ price and high gas price scenarios, Portfolios B1, B2, and C1 all perform in the top 3 most cost-effective portfolios in the scenarios, with the maximum regret of these portfolios in these scenarios being less than $0.8 billion on a PVRR through 2050. This shows the benefit of leveraging existing, proven, and cost-effective technologies to begin transitioning the fleet to a lower carbon future.

Overall, the minimax regret analysis clear distinction between the first six portfolios and the latter three portfolios, with, depending on the scenario and how costs are accounted for, any of the six may be optimal.

## AVERAGE RESIDENTIAL MONTHLY BILL IMPACT

As previously noted, the total present value of revenue requirement (PVRR) of a plan is a common and useful financial metric in Integrated Resource Planning to measure the cost of the plan over a long period of time. This metric captures the costs and benefits of accelerating retirements, building new generation and associated transmission, and changing fuel prices and operation costs over time. While this is an important metric, the Company is also concerned about the cost to customers on an immediate basis, as providing affordable energy is critical to the Company's mission. The analysis of estimating the average residential monthly bill impact attempts to quantify how much a residential customer using 1,000 kWh of energy per month can expect to see their bill change over 2020 costs of service due to the changes identified in this IRP. As discussed in the September 2020 IRP, these bill impacts only account for changes captured in the IRP and do not represent an all-inclusive bill impact analysis as other factors can also influence a customer's bill.

Below, Table 3-V shows the resulting changes to a typical residential customer's bill for each of the portfolios through 2030 and 2035. Additionally, the average annual percentage change from 2020 through 2030 and through 2035 is also shown representing how much a customer's bill would increase on average over that time frame. The results shown for this analysis are in the Company's base gas price, base battery price and base carbon price scenario, while excluding the explicit cost of the carbon price on emissions to customers.

### TABLE 3-V
### SCENARIO ANALYSIS AVERAGE MONTHLY RESIDENTIAL BILL IMPACT FOR A HOUSEHOLD USING 1000 KWH/MO, NOMINAL $

| | 2030 | | 2035 | |
|---|---|---|---|---|
| | Average Residential Monthly Bill Impact | Average Annual Percentage Change in Residential Bills | Average Residential Monthly Bill Impact | Average Annual Percentage Change in Residential Bills |
| A1 | $13 | 1.1% | $21 | 1.2% |
| A2 | $13 | 1.2% | $22 | 1.2% |
| B1 | $11 | 1.1% | $23 | 1.3% |
| B2 | $12 | 1.1% | $24 | 1.3% |
| C1 | $15 | 1.3% | $23 | 1.3% |
| C2 | $14 | 1.3% | $23 | 1.3% |
| D1 | $33 | 2.8% | $40 | 2.2% |
| E1 | $29 | 2.5% | $37 | 2.0% |
| F1 | $51 | 4.1% | $58 | 2.9% |

Table 3-V shows that the portfolios with earlier transitions to lower carbon future portfolios and more expensive technologies will lead to higher bill impacts earlier, while the portfolios that wait longer to transition, and allow for emerging technologies to decrease in price generally lead to lower costs for customers. With projected declining cost curves for emerging carbon-free resources, the pace of adoption plays a critical role in the ultimate cost to consumers. Because DEP must replace its coal fleet by 2030, when using the most economic retirement dates in Portfolio F1, the integration of 2,400 MW of offshore wind and the associated transmission in DEP drive the customer bill impacts up before 2030, and continue increasing due to continued addition of battery energy storage to meeting DEP's growing system load requirements.

As expected, the bill impacts for Portfolios A1 and A2 are essentially the same. The same can be observed for Portfolios B1 and B2, which only slightly diverge, with more batteries included in Portfolio B2. The two portfolios perform similarly across a range of metrics and analyses, with customer bill impacts continuing to show this trend.

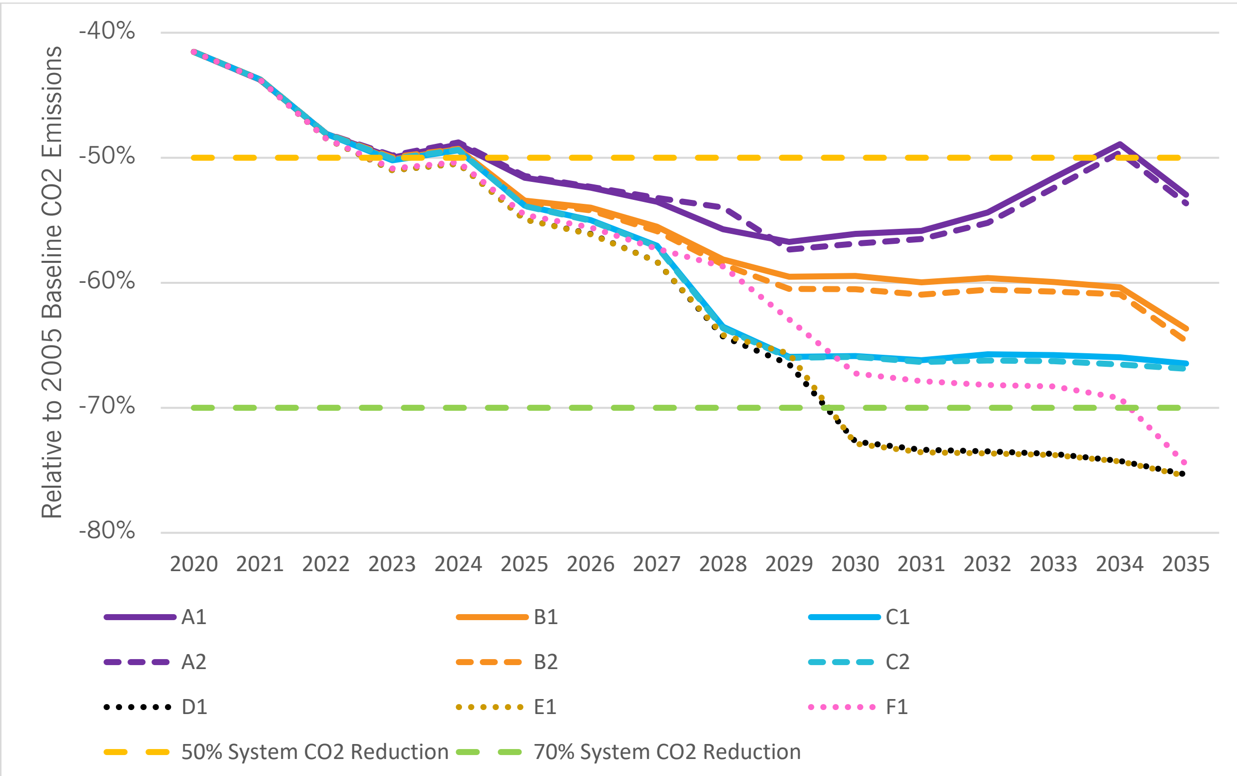
It should be noted that integrating large scale regional energy infrastructure projects, such as bringing offshore wind energy into the Carolinas, would likely require supportive state policies, including allocation of costs for resources and transmission infrastructure to move the energy from the coast to load centers all customers in the Carolinas rather than those of a single utility. Notwithstanding this possibility, for the purposes of developing the No New Gas Portfolio, all energy, capacity, and associated costs for the results shown are for DEP only, with the recognition that future energy policy could potentially be more evenly spread costs across utilities.

## PORTFOLIO CARBON REDUCTIONS ANALYSIS

While cost is undoubtably an important factor, one of the most crucial aspects analyzed in this supplemental IRP analysis and in the original IRP analysis filed in 2020 is the trade-off between costs and carbon reductions. The graph below charts the carbon reductions for the combined DEP/DEC system for each of the portfolios in the base fuel and base carbon scenario through the IRP planning window. The resources added throughout time, price on carbon emissions (or lack thereof), and relative price between fuels influence these portfolio emissions.

### FIGURE 3-O

### COMBINED DEP/DEC CARBON REDUCTION BY PORTFOLIO IN BASE FUEL AND CORRESPONDING CARBON SCENARIO, FROM 2005 BASELINE




Through 2024 there are no notable differences in $CO_2$ emission reductions between the portfolios. Portfolios A1 and A2 continue a trajectory of lowering $CO_2$ emissions through 2029, albeit at a slower pace than other pathways, as low cost, less $CO_2$-intense natural gas and increasing penetration of solar offsets more $CO_2$-intense coal generation. As gas price begins to rise in the transition from market fuel prices to fundamental fuel prices in the Company's base natural gas fuel forecast, less expensive coal generation becomes more prevalent when a carbon policy is not present. Upon the retirement of Marshall station in 2035, and replacement with gas generation, Portfolios A1 and A2 see a reduction in $CO_2$ emissions again at the end of the planning horizon. As expected, with the resources in the two portfolios being nearly identical, the $CO_2$ reduction trajectories track each other throughout the planning horizon.

Increasing additions of solar generation in Portfolios B1 and B2 allow for further $CO_2$ emissions reduction as economic pressure from the price on $CO_2$ increases. Growing load and rising gas prices offset the reductions realized by renewables additions in the 2030s, resulting in flat $CO_2$ emissions until 2035, when Marshall is retired. Similar to the relationship between Portfolios A1 and A2, Portfolio B1 and Portfolio B2 $CO_2$ reduction trajectories track each other throughout the planning horizon, due to largely similar resource mixes.

As additional coal retirements occur throughout the mid-2020s in the portfolios that follow the earliest practicable coal retirement dates, Portfolios C1, C2, D1, and E1, the $CO_2$ reductions between the pathways begin to diverge from the economically optimized portfolios, resulting in a range of $CO_2$ reduction of 65% to 72% from 2005 baseline by 2030. While $CO_2$ reductions for Portfolios C1 and C2 largely flatten after 2030 as growing load is met with incremental renewables, Portfolios D1 and E1 continue to reduce $CO_2$ emissions past 70% with the introduction of offshore wind and new nuclear SMRs to the portfolios, respectively. With Portfolio F1, following the most economic coal retirements schedule, $CO_2$ reductions flatten from 2029 through 2034, until Marshall retires in 2035. By 2035, Pathways D1, E1, and F1 converge again around 75% $CO_2$ reduction, when the resource types in these portfolios align at the end of the IRP horizon with similar penetrations of carbon-free resources.

### TABLE 3-W
### COMBINED DEP/DEC SCENARIO $CO_2$ REDUCTIONS IN 2030 FOR EACH PORTFOLIO FROM 2005 BASELINE

| PORTFOLIO | A1 | A2 | B1 | B2 | C1 | C2 | D1 | E1 | F1 |
|---|---|---|---|---|---|---|---|---|---|
| High $CO_2$ / Duke High Fuel | 56.4% | 57.2% | 58.8% | 59.9% | 65.9% | 66.0% | 72.7% | 72.9% | 66.8% |
| High $CO_2$ / Alternate High Fuel | 55.0% | 55.8% | 57.5% | 58.6% | 65.9% | 66.0% | 72.7% | 73.0% | 65.5% |
| High $CO_2$ / Duke Base Fuel | 57.1% | 57.9% | 59.6% | 60.6% | 65.9% | 66.0% | 72.7% | 72.9% | 67.5% |
| High $CO_2$ / Alternate Base Fuel | 57.2% | 57.9% | 59.6% | 60.6% | 65.9% | 66.0% | 72.7% | 73.0% | 67.2% |
| High $CO_2$ / Duke Low Fuel | 57.3% | 58.0% | 59.7% | 60.8% | 65.9% | 65.9% | 72.7% | 72.9% | 67.6% |
| High $CO_2$ / Alternate Low Fuel | 57.3% | 58.0% | 59.7% | 60.8% | 65.9% | 66.0% | 72.7% | 72.9% | 67.5% |
| Base $CO_2$ / Duke High Fuel | 56.3% | 57.0% | 58.7% | 59.7% | 65.9% | 66.0% | 72.7% | 72.9% | 66.5% |
| Base $CO_2$ / Alternate High Fuel | 52.9% | 53.6% | 55.4% | 56.5% | 65.9% | 66.0% | 72.7% | 73.0% | 63.7% |
| Base $CO_2$ / Duke Base Fuel | 57.0% | 57.8% | 59.5% | 60.5% | 65.9% | 65.9% | 72.7% | 72.9% | 67.2% |
| Base $CO_2$ / Alternate Base Fuel | 56.8% | 57.6% | 59.3% | 60.3% | 65.9% | 66.0% | 72.7% | 72.9% | 66.9% |
| Base $CO_2$ / Duke Low Fuel | 57.2% | 58.0% | 59.6% | 60.7% | 65.8% | 65.9% | 72.7% | 72.8% | 67.6% |
| Base $CO_2$ / Alternate Low Fuel | 57.2% | 58.0% | 59.6% | 60.7% | 65.9% | 66.0% | 72.7% | 72.9% | 67.5% |
| No $CO_2$ / Duke High Fuel | 54.0% | 54.7% | 56.4% | 57.4% | 65.8% | 65.9% | 72.7% | 72.8% | 64.5% |

| PORTFOLIO | A1 | A2 | B1 | B2 | C1 | C2 | D1 | E1 | F1 |
|---|---|---|---|---|---|---|---|---|---|
| No $CO_2$ / Alternate High Fuel | 47.8% | 48.5% | 50.4% | 51.6% | 65.9% | 66.0% | 72.7% | 72.9% | 59.3% |
| No $CO_2$ / Duke Base Fuel | 56.1% | 56.9% | 58.5% | 59.5% | 65.7% | 65.8% | 72.6% | 72.8% | 66.4% |
| No $CO_2$ / Alternate Base Fuel | 52.7% | 53.4% | 55.2% | 56.3% | 65.9% | 65.9% | 72.7% | 72.9% | 63.3% |
| No $CO_2$ / Duke Low Fuel | 56.6% | 57.3% | 59.1% | 60.0% | 65.5% | 65.6% | 72.4% | 72.4% | 66.9% |
| No $CO_2$ / Alternate Low Fuel | 56.6% | 57.3% | 59.0% | 60.0% | 65.8% | 65.9% | 72.6% | 72.8% | 66.9% |
| Reduction Range | 9.5% | 9.5% | 9.3% | 9.2% | 0.4% | 0.4% | 0.4% | 0.6% | 8.3% |

TABLE 3-X

COMBINED DEP/DEC SCENARIO $CO_2$ REDUCTIONS IN 2035 FOR EACH PORTFOLIO FROM 2005 BASELINE

| PORTFOLIO | A1 | A2 | B1 | B2 | C1 | C2 | D1 | E1 | F1 |
|---|---|---|---|---|---|---|---|---|---|
| High $CO_2$ / Duke High Fuel | 56.2% | 56.8% | 62.9% | 63.9% | 66.5% | 66.9% | 75.4% | 75.5% | 73.9% |
| High $CO_2$ / Alternate High Fuel | 56.2% | 56.8% | 62.9% | 63.9% | 66.5% | 66.9% | 75.3% | 75.5% | 73.8% |
| High $CO_2$ / Duke Base Fuel | 57.3% | 58.0% | 63.9% | 64.9% | 66.5% | 66.9% | 75.4% | 75.5% | 74.8% |
| High $CO_2$ / Alternate Base Fuel | 57.4% | 58.2% | 64.1% | 65.0% | 66.5% | 66.9% | 75.4% | 75.5% | 74.9% |
| High $CO_2$ / Duke Low Fuel | 57.4% | 58.0% | 64.0% | 65.0% | 66.5% | 66.9% | 75.3% | 75.5% | 75.0% |
| High $CO_2$ / Alternate Low Fuel | 57.4% | 58.0% | 64.0% | 64.9% | 66.5% | 66.9% | 75.4% | 75.4% | 75.0% |
| Base $CO_2$ / Duke High Fuel | 53.9% | 54.7% | 60.9% | 62.0% | 66.5% | 66.9% | 75.3% | 75.5% | 72.2% |
| Base $CO_2$ / Alternate High Fuel | 53.9% | 54.7% | 60.9% | 62.0% | 66.5% | 66.9% | 75.3% | 75.5% | 72.2% |
| Base $CO_2$ / Duke Base Fuel | 57.0% | 57.7% | 63.7% | 64.7% | 66.5% | 66.9% | 75.3% | 75.4% | 74.5% |
| Base $CO_2$ / Alternate Base Fuel | 57.2% | 58.0% | 63.9% | 64.8% | 66.5% | 66.9% | 75.3% | 75.5% | 74.7% |
| Base $CO_2$ / Duke Low Fuel | 57.3% | 58.0% | 64.0% | 64.9% | 66.5% | 66.9% | 75.3% | 75.4% | 74.8% |
| Base $CO_2$ / Alternate Low Fuel | 57.3% | 58.0% | 63.9% | 64.9% | 66.5% | 66.8% | 75.3% | 75.4% | 74.8% |
| No $CO_2$ / Duke High Fuel | 49.4% | 50.1% | 56.5% | 57.7% | 66.5% | 66.8% | 75.3% | 75.4% | 68.2% |
| No $CO_2$ / Alternate High Fuel | 49.4% | 50.1% | 56.5% | 57.7% | 66.5% | 66.9% | 75.4% | 75.5% | 68.2% |
| No $CO_2$ / Duke Base Fuel | 53.0% | 53.7% | 59.9% | 61.0% | 66.4% | 66.9% | 75.3% | 75.4% | 71.1% |
| No $CO_2$ / Alternate Base Fuel | 53.8% | 54.5% | 60.7% | 61.9% | 66.4% | 66.8% | 75.3% | 75.4% | 71.9% |
| No $CO_2$ / Duke Low Fuel | 55.4% | 56.1% | 62.2% | 63.2% | 66.3% | 66.8% | 75.2% | 75.3% | 73.1% |
| No $CO_2$ / Alternate Low Fuel | 55.4% | 56.1% | 62.2% | 63.2% | 66.3% | 66.8% | 75.2% | 75.3% | 73.1% |
| Reduction Range | 8.1% | 8.0% | 7.5% | 7.3% | 0.2% | 0.1% | 0.2% | 0.2% | 6.8% |

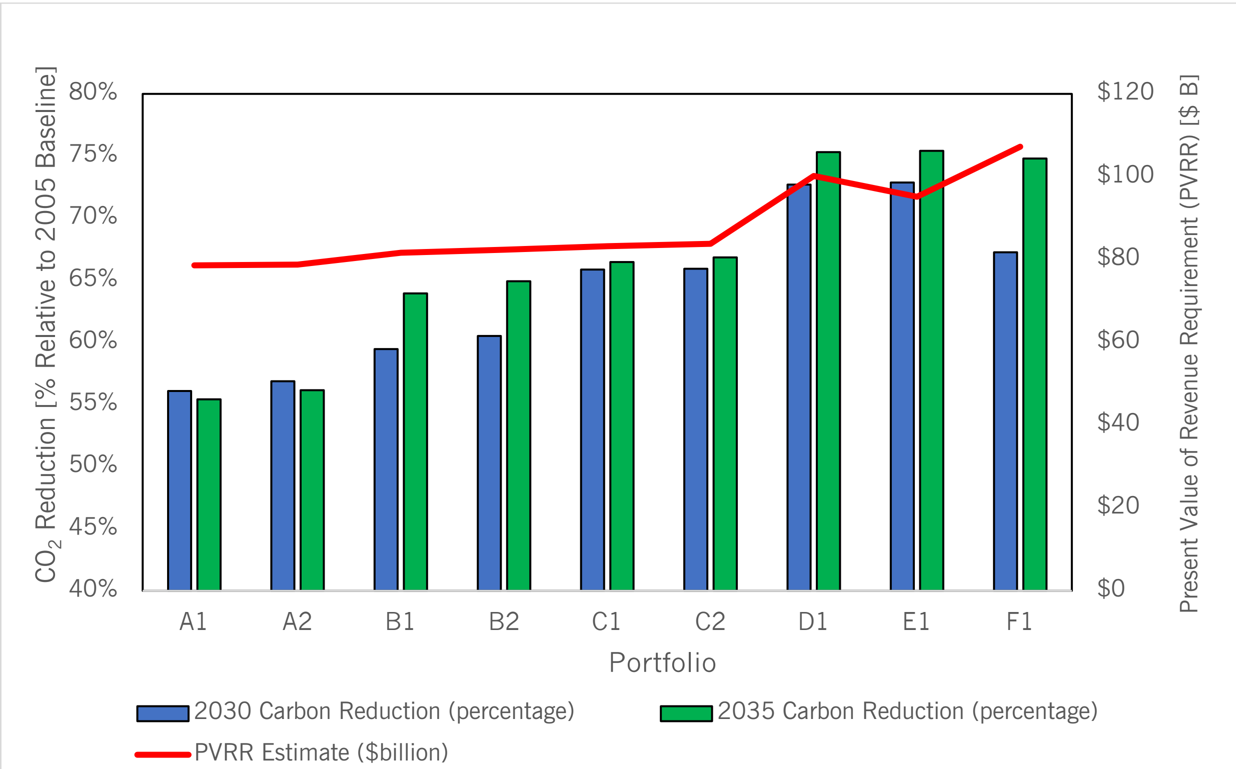
Through 2030, the portfolios for which carbon emissions are the most sensitive to changing input assumptions are the economically optimized portfolios and Portfolio F1, due to their continued operation of coal generation through the most economic retirement dates. In these portfolios, the dispatch and resulting emissions for the fossil units respond to the carbon price, whereas the renewables-heavy portfolios cannot change operations to adjust to price incentives. This can be observed in the $CO_2$ reduction range for the remaining four portfolios (Portfolios C1, C2, D1, and E1). The reduction ranges are relatively tight, within a 0.6% or less range for the portfolios that utilize the earliest practicable retirement dates. Portfolio F1, which does not deploy new natural gas is still fairly sensitive to a combination of the lack of a price on carbon, and a relatively high gas price, as seen in the alternate high gas forecast as coal runs more.

These observations though 2030 are reinforced through 2035. The portfolios with the most economic coal retirement dates see ranges of carbon reductions from 6.8% in Portfolio F1 to 8.1% in Portfolio A1. The portfolios with higher costs also consistently deliver the highest levels of carbon reductions. Emissions in these portfolios vary little with changes to carbon and fuel pricing, which is expected given the resources deployed in these portfolios.

Furthermore, below in Figure 3-P is a chart of the costs of each of the portfolios compared to their 2030 and 2035 carbon reductions assuming the Company's base gas price and battery cost.

FIGURE 3-P

## ESTIMATED COMBINED SYSTEM TOTAL PVRR THROUGH 2050 AND CARBON REDUCTIONS IN 2030 AND 2035, FROM A 2005 BASELINE




Higher carbon reductions achieved in Portfolios D1, E1, and F1 are the result of investments in additional carbon-free resources needed to achieve those reduction levels. Portfolios C1 and C2 achieve greater carbon reductions by 2030 and 2035 as compared to B1 and B2, with only minor overall PVRR increases. This impact illustrates that accelerating coal retirements, in an orderly and well-planned manner, taking advantage of existing infrastructure and using existing, proven, and cost-effective resources, can accelerate carbon reductions with only marginal cost increases to the customer.

## IDENTIFYING ADDITIONAL OPPORTUNITIES AND RISK MITIGATION

While each of these plans comes with inherent risks, such as exposure to fuel and carbon pricing or early adoption of emerging technologies with cost and operational uncertainties, the Company will have to continue to have constructive conversations with stakeholders and regulators to identify and mitigate risks that would hinder the Company from providing clean, affordable, and reliable energy. Below discusses some of these risks and mitigating measures:

- **Earliest Practicable Coal Retirements** – While the PVRR and Average Residential Monthly Bill Impact results for Earliest Practicable Coal Retirements are relatively comparable to the economically optimized portfolios with carbon policy, this portfolio does present additional potential tradeoffs and dependency on several factors. The regulatory approval and feasibility of procuring the replacement generation are foremost on this list. Additionally, some of the earliest practicable coal retirements are predicated on replacement onsite, leveraging existing infrastructure. This assumption avoids transmission upgrades at some of the retiring coal sites to reduce replacement timelines, and results in lower costs of the plan. The most economic retirement dates of the coal units do not assume replacement at the existing sites, and do not benefit from this cost savings. This provides optionality in the replacement process for the cheapest alternatives to be selected but does incur more cost to the portfolios for the associated transmission upgrades. Project cost risks associated with these accelerated retirements may put stresses on supply chain driving price variations. Furthermore, the Company supports a methodical and appropriately paced approach to deploying economically and operationally maturing technologies, like batteries. Accelerated adoption presents increased cost risk and a steeper learning curve for the operational aspect of these resources. Finally opting for earlier retirement of coal units by relying on natural gas may impact deployment of lower carbon and zero-emitting load-following resource (ZELFR) technologies in the future or the associated customer impacts of doing so, so the Company must continue to discuss with stakeholders the tradeoffs of such schedule.

- **Solar Interconnection** – While solar and other intermittent technologies may help lower exposure to variability in the price of fuels and can help reduce carbon emissions, the interconnection and operation of these resources will have to continue to be studied and advanced to allow for affordable and reliable operation of the system.

- **Onshore Wind Integration** – Several studies throughout the industry identify the value of combining variable energy resources like solar and wind with different but potentially complimentary production profiles. Integration of these resources can help continue to lower carbon emissions and spur economic development in the region but overcoming the historic challenges to siting onshore wind in the Carolinas is an issue that requires further study.

- **Offshore Wind Integration –** A largely untapped resource sits just off the coast of the Carolinas. While there are several hurdles to incorporating this new generation source in the Carolinas systems, such as construction of these offshore wind resources, transmitting that energy to land and then delivering it to the Company's load centers, there is a great opportunity to further reduce carbon emissions and add bulk amounts of zero fuel cost generation to the fleet.

- **ZELFR Development –** While emerging technologies, such as SMRs, were evaluated in this IRP, developing a range of zero-emitting, load following resources will be important to de-risking the transition to a net-zero carbon future.

- **System Operability –** As the generation resource mix evolves in the Carolinas, system operators will have to continue to learn and adapt to new, intermittent and variable energy resources on the system to balance load and generation, utilizing and advancing the flexibility of the existing fleet, while leveraging resources like energy storage and demand side management to continue to provide safe and reliable energy. These transformations envisioned will also rely on significant advancements in the sophistication of the grid control systems needed to manage system operations with these more diverse and distributed new energy resources.

## OTHER FINDINGS AND INSIGHTS

- **Gas as a transition fuel –** The No New Gas Generation portfolio in this IRP demonstrates that natural gas remains a cost-effective way to accelerate the remaining coal retirements over the term of this IRP. Many independent studies and articles have supported the continued role of natural gas to balance the intermittency of renewables and continue to decarbonize the system. As shown in Figure 3-O, the No New Gas Portfolio emits more $CO_2$ over the fifteen-year period through 2035 and is more costly than Portfolios D1 and E1 that include natural gas as a dispatchable capacity replacement resource. Eliminating natural gas generation as an option is likely to have the unintended effect of delaying coal retirements and increasing $CO_2$ in the interim, as more coal generation is required to serve load without new efficient natural gas resources as a transition technology.

- **Gas transportation services** – DEP and DEC continue to show the need for additional firm interstate transportation service to support existing and future gas generation in the Carolinas. Diversity in supply continues to lower the cost of the system and de-risk natural gas price exposure from access to limited sources. The rapid transition out of coal would further benefit from access to new and existing natural gas pipelines to keep cost volatility low for customers, while providing a reliable fuel source and utilizing known, and cost-effective technologies.

- **Emerging technology decommissioning costs** – Industry research is beginning to address decommissioning challenges and costs and potential materials recycling opportunities for new and emerging technologies such as those in batteries, solar panels, and wind turbine blades. While the Company's capital cost for new technologies includes allowances for some costs at end of life for these assets, more long-term recycling benefits or disposal cost information will be needed to evaluate the opportunity cost of selecting these resources. Additionally, while it is unclear what costs are truly covered in the Solar PPA cost proxy used in the IRP, decommissioning costs of these resources may present future cost or disposal risks for these assets.

## 7. SELECTION OF A PREFERRED PORTFOLIO

As described in Section 1, Portfolio C1 is consistent with carbon reduction objectives the Company has embraced, using economic, proven technologies to ensure reliability and prioritize affordability for customers. In addition to the qualitative factors described in Section 1, the quantitative analysis in this section also contributed to the Company's decision to select Portfolio C1 as the preferred portfolio.

The quantitative analysis contributing to the selection of Portfolio C1 includes:

- Portfolio C1 provides consistent $CO_2$ reductions across a range of fuel and carbon price scenarios, at levels exceeding other portfolios that rely on later retirement dates.
- Portfolio C1 reduces potential customer compliance cost risk that would be associated with future environmental regulations on carbon emissions and coal plant operations.
- Portfolio C1 performs robustly across the Company's financial analyses of the supplemental IRP portfolio analysis.

Portfolio C1 provides the accelerated coal retirements, carbon reductions, and the transition of the fleet to lower carbon emissions sooner for a moderate cost increase. The slight increase in PVRR of Portfolio C1 in base gas and battery costs delivers a lower variation in PVRR results and reduced cost exposure range compared to the economically optimized portfolios A1, A2, B1, and B2. When evaluating the possibility of either the explicit cost of carbon emissions being passed on to customers or not, the maximum regret of this Portfolio C1 in line with the economically optimized portfolios, with a portfolio configuration that offsets risks for customers on how carbon policy may developed, while achieving more immediate, predictable and dependable carbon reductions.

## PORTFOLIO C1 – LOAD, CAPACITY, AND RESERVES AND PORTFOLIO CHANGE OVERPLANNING HORIZON

Tables 3-Y and 3-Z present the Load, Capacity and Reserves (LCR) tables for the Portfolio C1 analysis that was completed for DEP's supplemental IRP analysis.

# TABLE 3-Y

## PORTFOLIO C1: DEP – LOAD, CAPACITY AND RESERVES TABLE – WINTER

| | | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| ***Load Forecast*** | | | | | | | | | | | | | | | | |
| 1 | DEP System Winter Peak | 14,161 | 14,221 | 14,240 | 14,431 | 14,566 | 14,670 | 14,867 | 14,998 | 15,248 | 15,310 | 15,506 | 15,672 | 15,792 | 15,920 | 16,210 |
| 2 | Firm Sale | 150 | 150 | 150 | 150 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 3 | Cumulative New EE Programs | (43) | (78) | (111) | (141) | (185) | (214) | (238) | (258) | (272) | (276) | (273) | (268) | (262) | (254) | (243) |
| **4** | **Adjusted Duke System Peak** | **14,268** | **14,293** | **14,280** | **14,440** | **14,381** | **14,456** | **14,629** | **14,740** | **14,976** | **15,035** | **15,233** | **15,404** | **15,531** | **15,666** | **15,966** |
| ***Existing and Designated Resources*** | | | | | | | | | | | | | | | | |
| 5 | Generating Capacity | 14,197 | 13,683 | 13,683 | 13,683 | 13,683 | 13,687 | 12,709 | 12,709 | 10,253 | 10,253 | 10,263 | 10,263 | 10,263 | 10,263 | 10,263 |
| 6 | Designated Additions / Uprates | 0 | 0 | 0 | 0 | 4 | 0 | 0 | 6 | 0 | 10 | 0 | 0 | 0 | 0 | 0 |
| 7 | Retirements / Derates | (514) | 0 | 0 | 0 | 0 | (978) | 0 | (2,462) | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **8** | **Cumulative Generating Capacity** | **13,683** | **13,683** | **13,683** | **13,683** | **13,687** | **12,709** | **12,709** | **10,253** | **10,253** | **10,263** | **10,263** | **10,263** | **10,263** | **10,263** | **10,263** |
| ***Purchase Contracts*** | | | | | | | | | | | | | | | | |
| **9** | **Cumulative Purchase Contracts** | **2,673** | **2,518** | **2,500** | **2,484** | **2,476** | **2,428** | **2,432** | **2,425** | **2,374** | **2,374** | **2,375** | **2,361** | **2,232** | **2,231** | **2,231** |
| | Non-Compliance Renewable Purchases | 82 | 84 | 81 | 84 | 88 | 94 | 94 | 93 | 43 | 43 | 43 | 41 | 41 | 40 | 40 |
| | Non-Renewables Purchases | 2,591 | 2,434 | 2,419 | 2,400 | 2,388 | 2,334 | 2,337 | 2,332 | 2,332 | 2,332 | 2,332 | 2,320 | 2,191 | 2,191 | 2,191 |
| ***Undesignated Future Resources*** | | | | | | | | | | | | | | | | |
| 10 | Nuclear | | | | | | | | | | | | | | | |
| 11 | Combined Cycle | | | | | | | | 1,224 | | | | | | | |
| 12 | Combustion Turbine | | | | | | 457 | | 1,371 | 457 | | | 457 | | | 457 |
| 13 | Solar | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 4 | 4 | 4 | 4 | 4 |
| 13a | Solar PPA | 0 | 0 | 0 | 2 | 2 | 2 | 2 | 2 | 2 | 4 | 4 | 4 | 4 | 4 | 4 |
| 14 | Wind | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 50 | 50 | 50 | 50 |
| 15 | Storage | 0 | 0 | 105 | 210 | 211 | 223 | 254 | 0 | 0 | 0 | 0 | 0 | 33 | 33 | 33 |
| ***Renewables*** | | | | | | | | | | | | | | | | |
| **16** | **Cumulative Renewables Capacity** | **219** | **86** | **192** | **404** | **616** | **831** | **1,105** | **1,124** | **1,139** | **1,136** | **1,154** | **1,207** | **1,294** | **1,381** | **1,467** |
| | Renewables w/o Storage | 219 | 86 | 87 | 86 | 87 | 78 | 80 | 80 | 76 | 61 | 62 | 61 | 61 | 61 | 61 |
| | Solar w/ Storage (Solar Component) | 0 | 0 | 0 | 0 | 0 | 0 | 1 | 2 | 3 | 4 | 5 | 5 | 5 | 5 | 5 |
| | Solar w/ Storage (Storage Component) | 0 | 0 | 0 | 3 | 3 | 3 | 21 | 39 | 57 | 69 | 80 | 80 | 80 | 80 | 80 |
| **17** | **Combined Heat & Power** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **18** | **Grid-connected Energy Storage** | 16 | 16 | 19 | 19 | 21 | 21 | 21 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **19** | **Cumulative Production Capacity** | **16,590** | **16,319** | **16,425** | **16,641** | **16,870** | **16,536** | **16,835** | **16,986** | **17,408** | **17,415** | **17,433** | **17,930** | **17,887** | **17,973** | **18,517** |
| ***Demand Side Management (DSM)*** | | | | | | | | | | | | | | | | |
| **20** | **Cumulative DSM Capacity** | **507** | **517** | **521** | **519** | **329** | **336** | **344** | **354** | **367** | **384** | **404** | **425** | **447** | **467** | **484** |
| **21** | **IVVC Peak Shaving** | **-** | **-** | **9** | **19** | **96** | **97** | **98** | **99** | **100** | **100** | **101** | **102** | **103** | **104** | **105** |
| **22** | **Cumulative Capacity w/ DSM** | **17,098** | **16,836** | **16,955** | **17,179** | **17,295** | **16,970** | **17,277** | **17,438** | **17,875** | **17,899** | **17,938** | **18,457** | **18,438** | **18,544** | **19,106** |
| ***Reserves w/ DSM*** | | | | | | | | | | | | | | | | |
| 23 | Generating Reserves | 2,830 | 2,543 | 2,675 | 2,739 | 2,914 | 2,514 | 2,648 | 2,698 | 2,899 | 2,864 | 2,705 | 3,053 | 2,907 | 2,879 | 3,139 |
| **24** | **% Reserve Margin** | **19.8%** | **17.8%** | **18.7%** | **19.0%** | **20.3%** | **17.4%** | **18.1%** | **18.3%** | **19.4%** | **19.1%** | **17.8%** | **19.8%** | **18.7%** | **18.4%** | **19.7%** |

## TABLE 3-Z

## PORTFOLIO C1: DEP – LOAD, CAPACITY AND RESERVES TABLE – SUMMER

| | | 2021 | 2022 | 2023 | 2024 | 2025 | 2026 | 2027 | 2028 | 2029 | 2030 | 2031 | 2032 | 2033 | 2034 | 2035 |
|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|---|
| ***Load Forecast*** | | | | | | | | | | | | | | | | |
| 1 | DEP System Summer Peak | 12,885 | 12,909 | 12,913 | 13,063 | 13,207 | 13,381 | 13,461 | 13,589 | 13,833 | 13,918 | 14,093 | 14,241 | 14,377 | 14,499 | 14,757 |
| 2 | Firm Sale | 150 | 150 | 150 | 150 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| 3 | Cumulative New EE Programs | (67) | (101) | (133) | (162) | (191) | (220) | (245) | (265) | (281) | (287) | (286) | (282) | (277) | (247) | (237) |
| **4** | **Adjusted Duke System Peak** | **12,968** | **12,957** | **12,930** | **13,051** | **13,016** | **13,161** | **13,216** | **13,324** | **13,552** | **13,631** | **13,807** | **13,959** | **14,100** | **14,252** | **14,520** |
| ***Existing and Designated Resources*** | | | | | | | | | | | | | | | | |
| 5 | Generating Capacity | 12,838 | 12,838 | 12,838 | 12,838 | 12,840 | 12,840 | 11,937 | 11,941 | 9,502 | 9,508 | 9,508 | 9,508 | 9,508 | 9,508 | 9,508 |
| 6 | Designated Additions / Uprates | 0 | 0 | 0 | 2 | 0 | 0 | 4 | 0 | 6 | 0 | 0 | 0 | 0 | 0 | 0 |
| 7 | Retirements / Derates | 0 | 0 | 0 | 0 | 0 | (903) | 0 | (2,439) | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **8** | **Cumulative Generating Capacity** | **12,838** | **12,838** | **12,838** | **12,840** | **12,840** | **11,937** | **11,941** | **9,502** | **9,508** | **9,508** | **9,508** | **9,508** | **9,508** | **9,508** | **9,508** |
| ***Purchase Contracts*** | | | | | | | | | | | | | | | | |
| **9** | **Cumulative Purchase Contracts** | **2,779** | **2,671** | **2,695** | **2,698** | **2,717** | **2,698** | **2,700** | **2,691** | **2,639** | **2,637** | **2,636** | **2,631** | **2,490** | **2,487** | **2,485** |
| | Non-Compliance Renewable Purchases | 295 | 325 | 365 | 388 | 419 | 460 | 459 | 456 | 404 | 402 | 401 | 398 | 396 | 394 | 392 |
| | Non-Renewables Purchases | 2,485 | 2,346 | 2,330 | 2,311 | 2,298 | 2,237 | 2,240 | 2,235 | 2,235 | 2,235 | 2,235 | 2,234 | 2,094 | 2,094 | 2,094 |
| ***Undesignated Future Resources*** | | | | | | | | | | | | | | | | |
| 10 | Nuclear | | | | | | | | | | | | | | | |
| 11 | Combined Cycle | | | | | | | | 1,152 | | | | | | | |
| 12 | Combustion Turbine | | | | | | 419 | | 1,257 | 419 | | | 419 | | | 419 |
| 13 | Solar | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 23 | 23 | 23 | 23 | 23 |
| 13a | Solar PPA | 0 | 0 | 0 | 11 | 11 | 11 | 11 | 11 | 11 | 23 | 23 | 23 | 23 | 23 | 23 |
| 14 | Wind | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 50 | 50 | 50 | 50 |
| 15 | Storage | 0 | 0 | 124 | 229 | 232 | 244 | 275 | 0 | 0 | 0 | 0 | 0 | 38 | 38 | 38 |
| ***Renewables*** | | | | | | | | | | | | | | | | |
| **16** | **Cumulative Renewables Capacity** | **347** | **230** | **234** | **247** | **248** | **238** | **287** | **335** | **378** | **394** | **449** | **528** | **617** | **697** | **785** |
| | Renewables w/o Storage | 347 | 230 | 234 | 242 | 243 | 233 | 254 | 273 | 288 | 285 | 298 | 297 | 296 | 294 | 293 |
| | Solar w/ Storage (Solar Component) | 0 | 0 | 0 | 2 | 2 | 2 | 12 | 23 | 33 | 40 | 47 | 47 | 46 | 46 | 46 |
| | Solar w/ Storage (Storage Component) | 0 | 0 | 0 | 3 | 3 | 3 | 21 | 39 | 57 | 69 | 80 | 89 | 107 | 116 | 134 |
| **17** | **Combined Heat & Power** | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **18** | **Grid-connected Energy Storage** | 16 | 16 | 19 | 19 | 21 | 21 | 21 | 0 | 0 | 0 | 0 | 0 | 0 | 0 | 0 |
| **19** | **Cumulative Production Capacity** | **15,980** | **15,771** | **15,818** | **15,855** | **15,895** | **15,403** | **15,479** | **15,488** | **15,904** | **15,918** | **15,972** | **16,466** | **16,413** | **16,490** | **16,996** |
| ***Demand Side Management (DSM)*** | | | | | | | | | | | | | | | | |
| **20** | **Cumulative DSM Capacity** | **966** | **976** | **980** | **979** | **786** | **788** | **789** | **791** | **794** | **796** | **800** | **803** | **806** | **809** | **812** |
| **21** | **IVVC Peak Shaving** | **-** | **-** | **9** | **19** | **96** | **97** | **98** | **99** | **100** | **100** | **101** | **102** | **103** | **104** | **105** |
| **22** | **Cumulative Capacity w/ DSM** | **16,946** | **16,746** | **16,807** | **16,854** | **16,777** | **16,288** | **16,366** | **16,377** | **16,798** | **16,815** | **16,873** | **17,371** | **17,322** | **17,404** | **17,913** |
| ***Reserves w/ DSM*** | | | | | | | | | | | | | | | | |
| 23 | Generating Reserves | 3,978 | 3,789 | 3,877 | 3,802 | 3,761 | 3,127 | 3,150 | 3,054 | 3,246 | 3,184 | 3,066 | 3,412 | 3,222 | 3,152 | 3,392 |
| **24** | **% Reserve Margin** | **30.7%** | **29.2%** | **30.0%** | **29.1%** | **28.9%** | **23.8%** | **23.8%** | **22.9%** | **24.0%** | **23.4%** | **22.2%** | **24.4%** | **22.9%** | **22.1%** | **23.4%** |

The following notes are numbered to match the line numbers on the Winter Projections of Load, Capacity, and Reserves tables. All values are MW (winter ratings) except where shown as a percent. Dates represented are COD dates, unless otherwise noted.

## TABLE 3-AA
## DEP - ASSUMPTIONS OF LOAD, CAPACITY, AND RESERVES TABLES

| Line Item | Line Inclusion[1] |
|---|---|
| 1. | Peak demand for the Duke Energy Progress System. This represents the base peak demand. |
| 2. | Firm sale of 150 MW through 2024. |
| 3. | Cumulative new energy efficiency and conservation programs (does not include demand response programs). |
| 4. | Peak load adjusted for firm sales and cumulative energy efficiency. |
| 5. | Existing generating capacity reflecting the impacts of designated additions, planned uprates, retirements and derates as of July 1, 2020. |
| 6. | Designated Capacity Additions |
| | Nuclear uprates:<br>Brunswick 1: 4 MW deployed in year 2024.<br>Brunswick 2: 6 MW deployed in year 2028 and 10 MW in 2029. |
| 7. | Estimated retirement dates for planning that represent the earliest practicable retirement dates determined in the 2020 coal retirement analysis. Other units represent estimated retirement dates based on the depreciation study approved in the most recent DEP rate case:<br>Mayo 1 (704 MW): December 2025<br>Roxboro 1-4 (2,462 MW): December 2027 |
| | All nuclear units are assumed to have subsequent license renewal at the end of the current license. |
| | All hydro facilities are assumed to operate through the planning horizon. |
| | All retirement dates are subject to review on an ongoing basis. Dates used in the 2020 SC Modified IRP are for planning purposes only, unless the unit is already planned for retirement. |
| 8. | Sum of lines 5 through 7. |

[1] Capacity must be on-line by June 1 to be included in available capacity for the summer peak of that year and by December 1 to be included in available capacity for the winter peak of the following year.

| Line Item | Line Inclusion[1] |
|---|---|
| 9. | Cumulative Purchase Contracts from traditional resources and renewable energy resources not used for NCREPS, NC HB589, SC Act 236 and SC Act 62 compliance. This is the sum of the next two lines. |
| | Non-Compliance Renewable Purchases includes purchases from renewable energy resources for which DEP does not own the REC. |
| | Non-Renewables Purchases are those purchases made from traditional generating resources. |
| 10. | New nuclear resources economically selected to meet load and minimum planning reserve margin. No nuclear resources were selected in the Portfolio C1: Earliest Practicable Coal Retirements in this IRP. |
| 11. | New combined cycle resources economically selected to meet load and minimum planning reserve margin. Addition of 1,224 MW of combined cycle capacity online in December 2027. |
| 12. | New combustion turbine resources economically selected to meet load and minimum planning reserve margin. The case presented has the addition of the following CTs:<br>457 MW CT in December 2025, December 2028, December 2031, and December 2034<br>1,371 MW CT in December 2027 |

<table>
<tr><th>Line Item</th><th>Line Inclusion[2]</th></tr>
<tr><td>13. and 13a.</td><td>
New solar resources economically selected to meet load and minimum planning reserve margin. Resources in the LCR table represents solar's contribution to peak based on the following table:
<table>
<tr><th>Min End of Range</th><th>Max End of Range</th><th>Winter</th></tr>
<tr><td>0</td><td>2,950</td><td>0.6%</td></tr>
<tr><td>2,951</td><td>3,290</td><td>3.2%</td></tr>
<tr><td>3,291</td><td>3,450</td><td>2.8%</td></tr>
<tr><td>3,450</td><td>100,000</td><td>2.7%</td></tr>
</table>
The Solar + Storage contribution to peak is approximately 25% in winter.<br><br>
The value in the table represents the nameplate capacity of the selected solar facilities. The case presented has the addition of the following solar resources:
<table>
<tr><th>Resource</th><th>Capacity Added:</th><th>Notes</th></tr>
<tr><td></td><td>150 MW in years 2031 through 2032</td><td>Includes solar component</td></tr>
<tr><td>Solar Only</td><td>225 MW in year 2032</td><td>of solar + storage</td></tr>
<tr><td>Solar + Storage</td><td>150 MW in year 2033 through 2035</td><td>Included in Line 13</td></tr>
<tr><td></td><td>75 MW in years 2024 through 2029</td><td></td></tr>
<tr><td>Solar PPA</td><td>150 MW in year 2030 through 2035</td><td>Included in Line 13a</td></tr>
</table>
</td></tr>
<tr><td>14.</td><td>New wind resources economically selected to meet load and minimum planning reserve margin. The value in the table represents the contribution to peak of the selected wind facilities. (33% for winter peak 7% for summer peak). The case presented has the addition 150 MW of wind resources in years 2032 through 2035.</td></tr>
<tr><td>15.</td><td>New battery storage resources economically selected to meet load and minimum planning reserve margin. The case presented has the addition of the following storage resources: 105 MW in year 2023; 210 MW in year 2024; 211 MW in year 2025; 223 MW in year 2026 and 254 MW in year 2027. Additionally, in years 2023 through 2035, the storage component of economically selected Solar + Storage of 33 MW is included.</td></tr>
<tr><td rowspan="2">16.</td><td>Cumulative Renewable Energy Contracts in and renewable energy resources used for NCREPS and NC HB589 compliance. This is the sum of the next three lines.</td></tr>
<tr><td>Renewables w/o Storage includes projected purchases from solar energy resources not paired with storage.</td></tr>
</table>

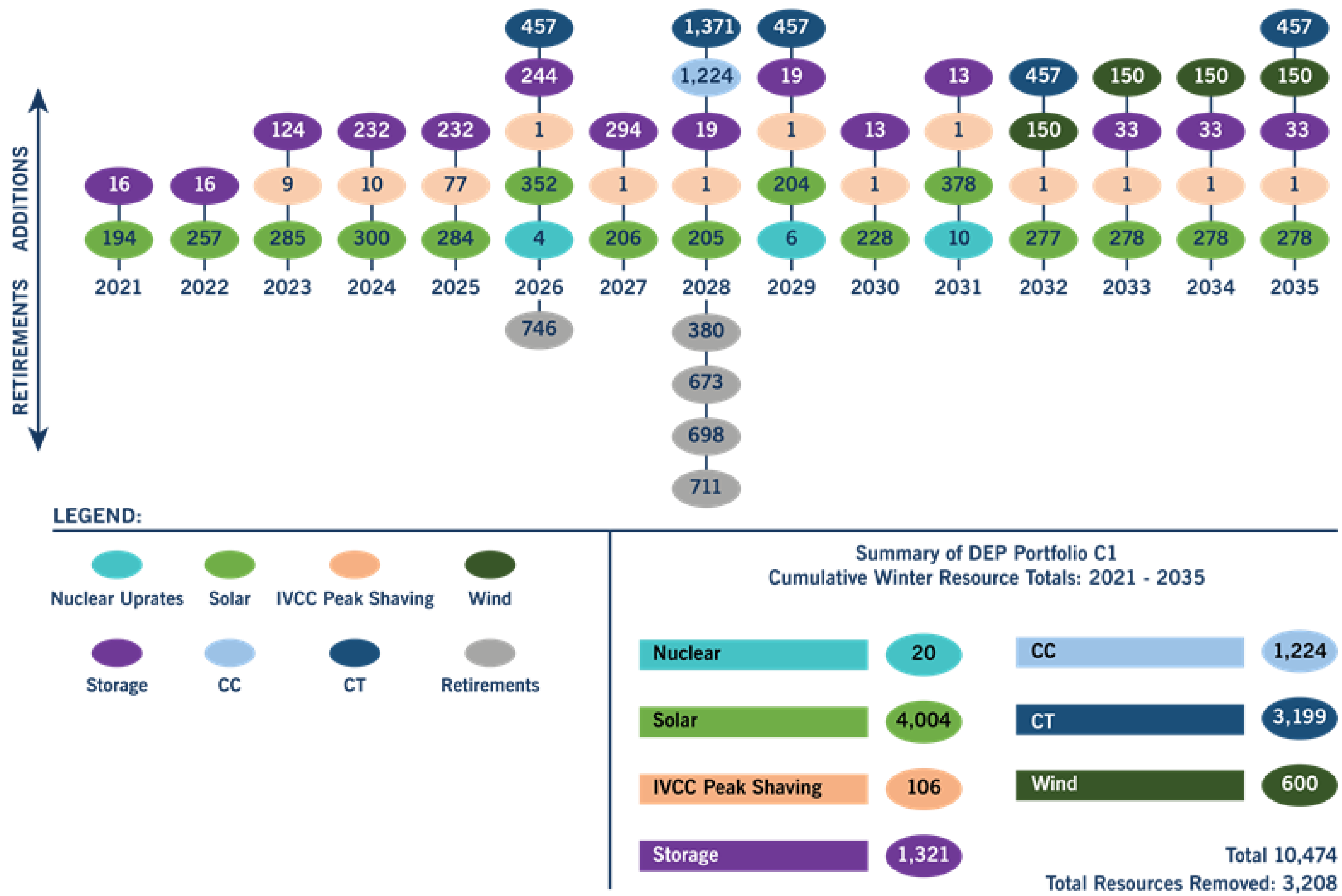
[2] Capacity must be on-line by June 1 to be included in available capacity for the summer peak of that year and by December 1 to be included in available capacity for the winter peak of the following year.

| Line Item | Line Inclusion[2] |
|---|---|
| | Solar w/ Storage (Solar Component) includes the solar component of projected solar energy resources paired with storage. |
| | Solar w/ Storage (Storage Component) includes the storage component of projected solar energy resources paired with storage. |
| 17. | Combined Heat and Power projects. There are no CHP projects included in the Portfolio C1: Earliest Practicable Coal Retirements for DEP. |
| 18. | Addition of 133 MW of grid-tied energy storage over years 2021 through 2027. |
| 19. | Cumulative total of lines 8 through 18. |
| 20. | Cumulative demand response programs including wholesale demand response. |
| 21. | Cumulative capacity associated with peak shaving of IVVC program. |
| 22. | Sum of lines 19 through 21. |
| 23. | The difference between lines 22 and 4. |
| 24. | Reserve Margin<br>RM = (Cumulative Capacity-System Peak Demand)/System Peak Demand.<br>Line 23 divided by Line 4.<br>Minimum winter target planning reserve margin is 17%. |

A graphical presentation of the Winter Portfolio C1 resource plan as represented in the above LCR table is shown below in Figure 3-Q. This figure provides annual incremental capacity additions to the DEP system by technology type. Additionally, a summary of the total resources by technology is provided below the figure.

FIGURE 3-Q

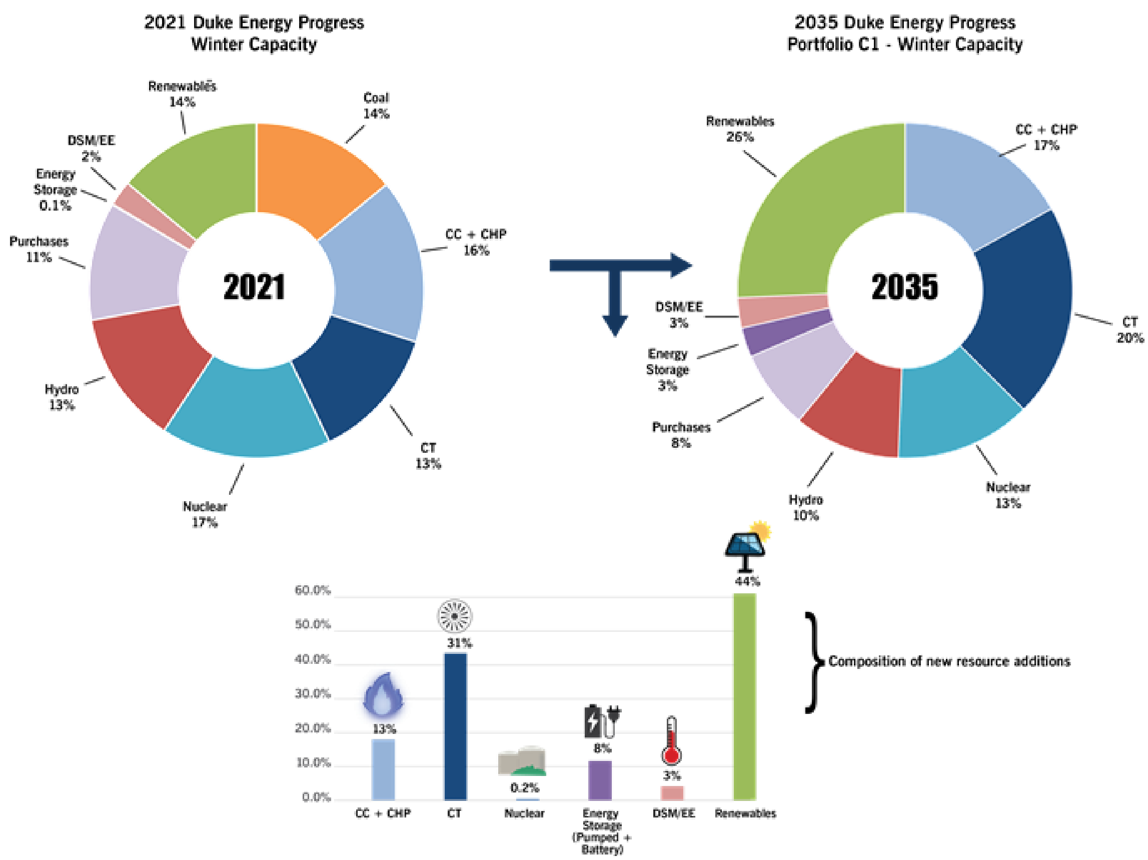
PORTFOLIO C1: DEP – ANNUAL ADDITIONS BY TECHNOLOGY



The following figures illustrate both the current and forecasted capacity for the DEP system, as projected by Portfolio C1. Figure 3-R depicts how the capacity mix for the DEP system changes with the passage of time. In 2035, Portfolio C1 projects that DEP will have a substantial reduction in its reliance on coal units and a significantly higher reliance on renewable resources as compared to the current state. It is of particular note that over 50% of the new resources added over the study period are solar, wind and storage resources.

As mentioned above, the resources in Portfolio C1 are depicted in Figure 3-R below reflects a significant amount of growth in solar capacity with nameplate solar growing from 2,888 MW in 2021 to 6,661 MW by 2035.

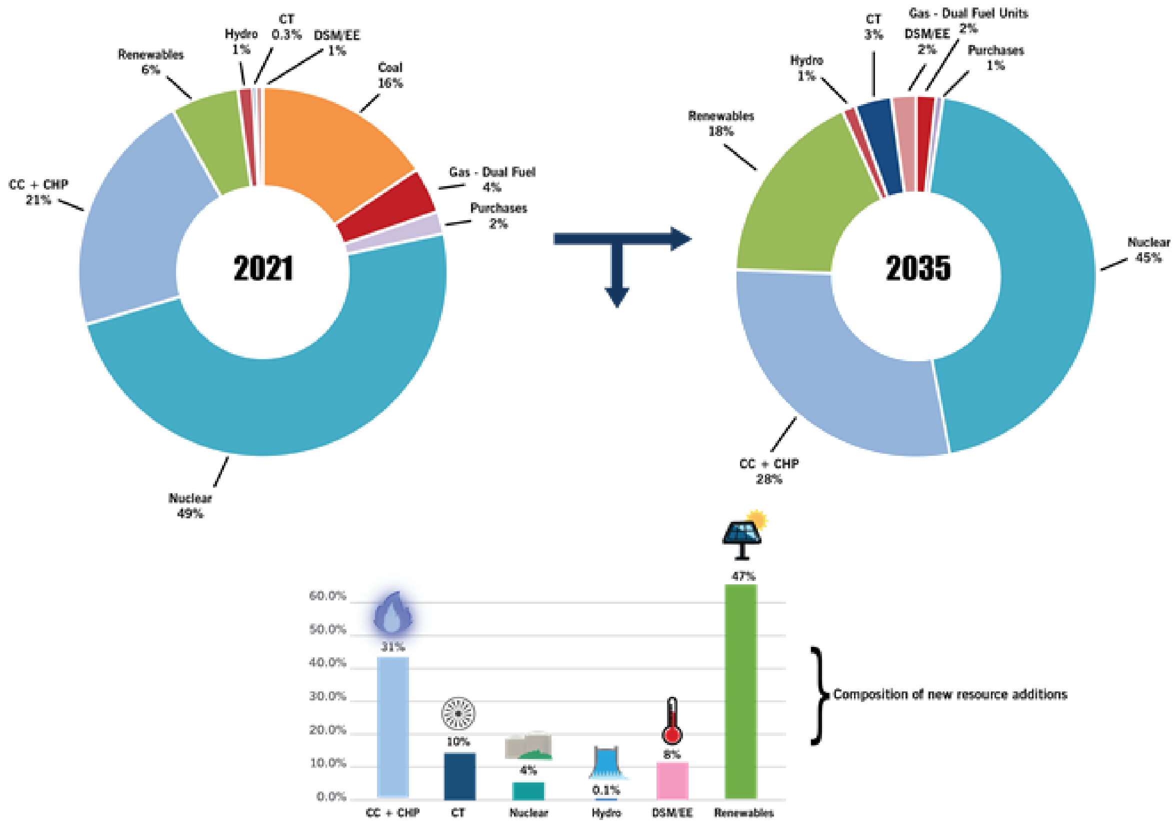
### FIGURE 3-R
### PORTFOLIO C1 – DEP CAPACITY CHANGES OVER 15 YEAR PLANNING HORIZON[3]




[3] All capacity based on winter ratings except Renewables and Energy Storage which are based on nameplate.

Figure 3-S represents the energy of both the DEC and DEP from Portfolio C1 over the IRP planning horizon. Due to the JDA, it is prudent to combine the energy of both utilities to develop a meaningful representation of energy for Portfolio C1. From 2021 to 2035, the figure shows that nuclear resources will continue to serve almost half of DEC and DEP's energy needs. Additionally, the figures display a substantial increase in the amount of energy served by carbon-free resources (solar, energy storage, solar plus storage, hydro and wind). Natural gas continues to remain an economical and reliable source of energy for the Company. It is of note that DEP has no reliance on coal in 2035.

## FIGURE 3-S
## PORTFOLIO C1 – DEC AND DEP COMBINED SYSTEM ENERGY OVER 15 YEAR PLANNING HORIZON[4]




[4] All capacity based on winter ratings except renewables and energy storage which are based on nameplate.

As noted, the further out in time planned additions or retirements are within the 2020 Modified IRP, the greater the opportunity for input assumptions to change. Thus, resource allocation decisions at the end of the planning horizon have a greater possibility for change as compared to those earlier in the planning horizon.